OPTIMIZING TECHNOLOGY TO REDUCE MERCURY AND ACID GAS EMISSIONS FROM ELECTRIC POWER PLANTS

Semi-Annual Report
August 1, 2004 to January 31, 2005

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Published February 2005

Prepared for The United States Department of Energy

Contract No. DE-FG26-03NT41901

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ABSTRACT

Revised maps and associated data show potential mercury, sulfur, and chlorine emissions for U.S. coal by county of origin. Existing coal mining and coal washing practices result in a 25% reduction of mercury in U.S. coal before it is delivered to the power plant. Selection of low-mercury coal is a good mercury control option for plants having hot-side ESP, cold-side ESP, or hot-side ESP/FGD emission controls. Chlorine content is more important for plants having cold-side ESP/FGD or SDA/FF controls; optimum net mercury capture is indicated where chlorine is between 500 and 1000 ppm. Selection of low-sulfur coal should improve mercury capture where carbon in fly ash is used to reduce mercury emissions.

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INTRODUCTION

Background

Switching to low-mercury-emission coal may be an effective strategy to comply with impending regulations that are intended to reduce mercury emissions from electric utilities. For example, despite proven emission control technology, burning low-sulfur coal is the most popular method to reduce sulfur emissions. Because technology to reduce mercury emissions is less certain, burning low-mercury coal is a likely method to reduce mercury emissions. Like sulfur, the amount of mercury in U.S. coal shows substantial geographic variation. However, unlike sulfur, mercury emissions also vary with the abundance of other elements in the coal, such as chlorine and sulfur, which influence mercury capture by emission control technologies. Consequently, mercury emission factors vary according to the relative abundance of several elements in the coal, and are specific to different emission control technologies.

This project uses Geographic Information System technology (ArcView GIS) to create detailed maps to show where U.S. coal with low-mercury and acid-gas emissions might be found. The map series will show geographic variation of mercury, chlorine, and sulfur in coal, as well as the mercury emission penalty, calculated for data aggregated by U.S. county-of-origin using equations specific to power plants classified by boiler type and flue gas emission controls. Removing mercury from flue gas is a technically complex task – different technologies will be required for different coals. Maps showing the geographic variation of mercury and acid-gas emission factors for U.S. coal will help locate the best coal for each technology and identify the best technology for each coal.

Coal quality data used in this study were described in a previous report (Quick and others, 2004a). Briefly, these data were selected from five data sets and include: 19,507 FERC 423 data records (USEIA, 2003a), 25,818 ICR data records (USEPA, 2003), 5602 CTRDB data records (USEIA, 2003b), 5045 COALQUAL data records (Bragg and others, 1997), and 73 PSU-DOE data records (Anonymous, 1990; Davis and Glick, 1993; Scaroni and others, 1999). Additional data considered in this report are from CEA (2004) and USMSHA (2004).

Scope

This report describes the progress made during the third six-month period of this 24-month project (figure 1). Results from task 6, and observations made while preparing a presentation (Quick and others, 2005) are described and discussed.

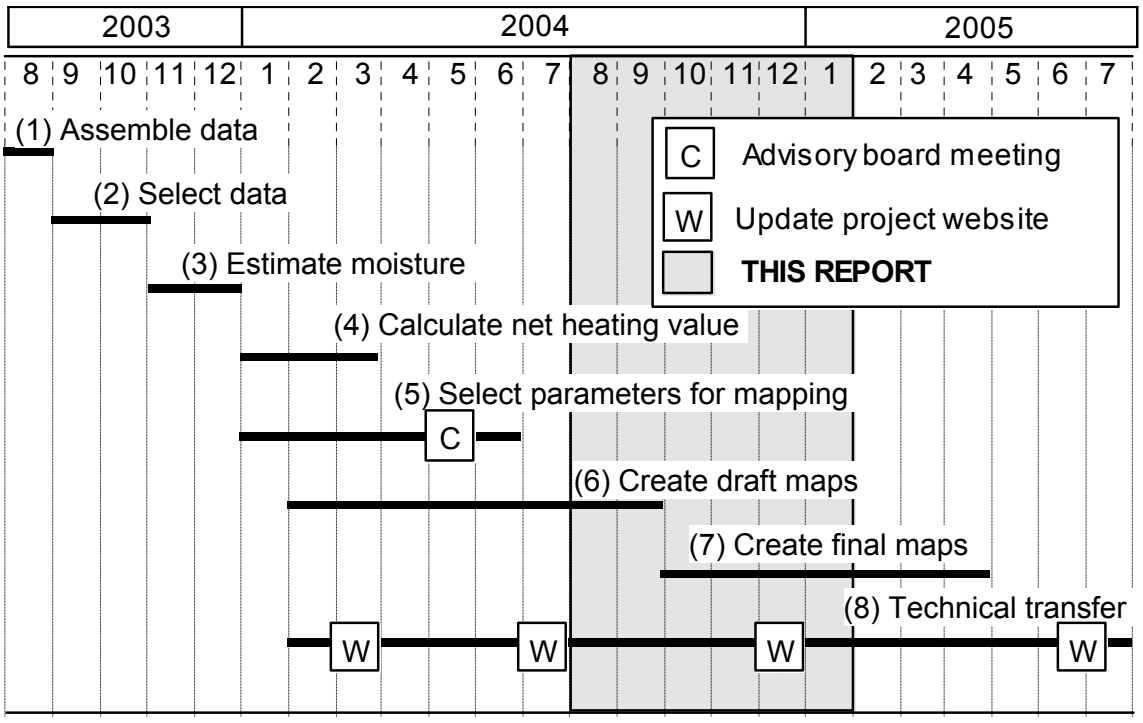

Figure 1. Schedule of project tasks.

EXECUTIVE SUMMARY

Revised, draft maps showing the geographic variation of mercury and acid-gas emission factors for U.S. coal by county of origin are presented, together with associated coal assay data. Three revisions to the maps presented in our August report (Quick and others, 2004b) include the following:

- ICR 2 coal assay data were identified for Panola/Rusk and Titus Counties Texas; although these records lack county-of-origin names, they correspond to a utility that burns local coal.
- New information suggests that the mercury assay values listed in the ICR 2 data for most coals from the Gulf Coast province are erroneously low. Where possible, new mercury values have been estimated for affected counties.
- Maps showing technology-specific mercury emission potentials were revised; the revised maps are now based on the average result of three predictive equations, rather than the result from just one equation.

Using the average mercury emission factors obtained from three equations, county-specific coal assay data, and estimates of 1999 county coal production, mercury capture is estimated for five existing emission control technologies (hot- side electrostatic precipitator [hESP], cold-side electrostatic precipitator [cESP], hot-side electrostatic precipitator with wet flue-gas desulfurization [hESP/FGD], cold-side electrostatic precipitator with wet flue-gas desulfurization [cESP/FGD], and spray-dry adsorption with fabric filter [SDA/FF] controls). A comparison of in-ground coal mercury to produced coal mercury was also made. Finally, empirical data from the Canadian Electricity Association (CEA, 2004) were used to evaluate the negative correlation between coal sulfur content and mercury capture. The results indicate:

- Selection of low-mercury coal is a reasonable way to reduce mercury emissions from units equipped with hESP, cESP, or hESP/FGD controls, whereas selection of coal with high-chlorine content is a better option for units with cESP/FGD, or SDA/FF controls.
- Blending high- and low-chlorine coals to an optimum level between 500 and 1000 ppm chlorine should provide a net reduction of mercury emissions for units with cESP/FGD, or SDA/FF controls.
- Although coal shipped to utilities contains about 25% less mercury than the in-ground resource, this difference is not geographically uniform. With the notable exception of Powder River Basin (PRB) coal from Wyoming, the mercury content of commercial coal from the western U.S., as well as Ohio, northern Pennsylvania, and the Gulf Coast, is similar or greater than the in-ground coal resource. Coal washing might be an effective mercury mitigation strategy in these areas.
- Selection of low-sulfur coal may improve mercury capture where carbon in fly ash is used to reduce mercury emissions.

EXPERIMENTAL

Work accomplished during this reporting period included data evaluation and revisions to draft maps. Related observations made while preparing for a conference presentation (Quick and others, 2005) are discussed.

Data Evaluation

Comparison of ICR 2 county origins, with 1999 county coal production (USEIA 2003a; USMSHA, 2004) showed that not all coal-producing counties are represented in the ICR data. This deficiency was especially acute for counties in Texas. Accordingly, 85 ICR 2 data records originating from the Martin Lake power station (but lacking county-of-origin information) were assigned to Panola and Rusk Counties, Texas. Likewise, 87 records from the Monticello station were assigned to Titus County. Notably, the Monticello records may include coal originating from nearby Hopkins County.

Comments to the USEPA related to the proposed mercury reduction rule (McCall, 2004; Eutizi, 2005; Glacken, 2005) suggest that the mercury values reported in the ICR 2 data for most Gulf Coast coal are erroneously low. Accordingly, average mercury values, from ICR 3 testing[1] or newly reported values (McCall, 2004; Eutizi, 2005), were used to estimate county-average mercury values for coal from Panola, Titus, Atascosa, Freestone, Milam, and Robertson Counties, Texas. Mercury values for Leon County, Texas, as well as Red River and De Soto Parishes, Louisiana, have not been revised and are probably too low.

[1] The ICR 3 data originate from measurements of atmospheric mercury emissions from about 80 selected U.S. power plants (USEPA, 2003). The data show measured mercury emissions and mercury capture observed during three, multiple hour intervals for each plant, and are complementary to the more comprehensive ICR 2 coal assay data.

Examination of coal supplier names listed in the ICR data identified nine records for coal from Washington County, Illinois, and seven records from Schuylkill County, Pennsylvania; these counties are now represented in the selected ICR 2 data. Table 1 lists the remaining counties missing from the selected ICR 2 data, together with their 1999 coal production. The missing counties represent 15.7 million tons, which is less than 2% of 1999 U.S. coal production.

Table 1. Coal production from counties not represented in the ICR 2 data selected for this study.

State	County	1999 production (tons)
Alabama	Bibb	44,500
Alabama	Cullman	35,700
Alabama	Marion	35,700
Alabama	Winston	338,500
Arkansas	Johnson	14,600
Colorado	Fremont	242,200
Colorado	La Plata	245,700
Illinois	Christian	72,200
Indiana	Dubois	72,800
Indiana	Spencer	204,400
Kentucky	Knox	506,100
Mississippi	Choctaw	18,400
Missouri	Barton	73,000
Ohio	Gallia	220,600
Ohio	Monroe	489,600
Ohio	Muskingum	663,100
Ohio	Noble	689,800
Ohio	Stark	316,400
Oklahoma	Craig	194,100
Pennsylvania	Carbon	39,300
Pennsylvania	Clarion	418,100
Pennsylvania	Jefferson	1,119,100
Pennsylvania	Lawrence	84,800
Pennsylvania	Sullivan	47,100
Pennsylvania	Venango	91,600
Texas	Hopkins	2,126,100
Texas	Webb	235,000
Virginia	Tazewell	2,062,700
West Virginia	McDowell	4,698,900
West Virginia	Mineral	48,500
West Virginia	Tucker	172,423
Wyoming	Sheridan	76,400

Revisions to Draft Maps

Various groups have used the ICR 3 utility emission data to derive equations that predict mercury capture for existing emission control technologies (Chu and others, 2000; Laumb and others, 2000; Roberson, 2002; ENSR, 2003; SAIC, 2003; AEMS, 2004). The equations use coal chlorine, ash, Btu, or sulfur values as independent variables to predict mercury capture. During the last reporting period, we applied selected equations to county-average coal assay data to create five technology-specific maps showing potential mercury emissions from U.S. coal. Because we lacked an independent utility emission data set to verify the selected equations, our selection of a single equation for each control technology was unavoidably arbitrary.

During the previous reporting period we also compared different equations that predict mercury emissions from units with SDA/FF emission controls. These equations all had similarly high reported r^2 values, they all predicted increasing capture with increasing coal chlorine, but they also predicted different results when applied to the same, county-average coal assay data. Accordingly, all of the predictive equations originally considered in this study were re-examined to check for possible transcription errors, and to verify the reporting basis of the independent variables. The result of this effort is shown in table 2, which lists three different equations for each of the (5) emission control technologies examined in this study. Figures 1, 2, 3, 4, and 5 compare the mercury capture predicted by these equations for each control technology. These results extend our earlier finding of similar r^2 values, similar trends, but different results, to include all five of the control technologies examined in this study (cESP, hsESP, hESP/FGD, cESP/FGD, and SDA/FF controls).

Table 2. Technology-specific equations that predict mercury capture.

TECHNOLOGY Reference	Equation to Predict Mercury Capture (100% capture = 1)	r^2	n
cESP			
Roberson (2002)	$0.1133\ Ln\left(\frac{Cl_{ppm,dry}}{1.998\ S_{wt.\%,dry}}\right) - 0.2987$	0.53	28
model 2, SAIC (2003)	$1 - Exp\left(-7.33E^{-2} - 3.309\left(lbs\ Cl\ per\ 10^{12}\ Btu\right)\right)$	0.47	12
model 1, SAIC (2003)	$1 - Exp\left(1.6374 - 0.18693 Ln\left(lbs\ Cl\ per\ 10^{12}\ Btu\right)\right)$	0.38	12
cESP/FGD			
Roberson (2002)	$0.1157\ Ln\left(Cl_{ppm,dry}\right) - 0.1438$	0.70	11
model 1, SAIC (2003)	$1 - Exp\left(1.8529 - 0.27149\ Ln\left(lbs\ Cl\ per\ 10^{12}\ Btu\right)\right)$	0.74	8
model 3, SAIC (2003)	$1 - Exp\left(-0.2559 - 2.3343E^{-5}\left(\frac{100\ Cl_{ppm,dry}}{S_{wt.\%,dry}}\right)\right)$	0.73	8
hESP			
model 1, SAIC (2003)	$1 - Exp\left(0.9451 - 9.995E^{-2} Ln\left(lbs\ Cl\ per\ 10^{12}\ Btu\right)\right)$	0.42	7
model 3, SAIC (2003)	$1 - Exp\left(0.0611 - 2.169E^{-6}\left(\frac{100\ Cl_{ppm,dry}}{S_{wt.\%,dry}}\right)\right)$	0.54	7
ENSR (2003)	$1 - Exp\left(0.12124 - 1.021E^{-4}\left(Cl_{ppm,dry}\right)\right)$	0.39	9
hESP/FGD			
model 1, SAIC (2003)	$1 - Exp\left(2.7019 - 0.29952\ Ln\left(lbs\ Cl\ per\ 10^{12}\ Btu\right)\right)$	0.75	6
model 2, SAIC (2003)	$1 - Exp\left(-3.59E^{-2} - 9.358E^{-6}\left(lbs\ Cl\ per\ 10^{12}\ Btu\right)\right)$	0.67	6
model 4, SAIC (2003)	$1 - Exp\left(2.5618 - 0.268 Ln\left(\frac{100\ Cl_{ppm,dry}}{S_{wt.\%,dry}}\right)\right)$	0.42	6
SDA/FF			
Roberson (2002)	$0.2854\ Ln\left(Cl_{ppm,dry}\right) - 1.1302$	0.91	10
model 1, SAIC (2003)	$1 - Exp\left(10.7111 - 1.22628\ Ln\left(lbs\ Cl\ per\ 10^{12}\ Btu\right)\right)$	0.89	10
ENSR (2003)	$1 - Exp\left(-0.19992 - 2.164E^{-3}\left(Cl_{ppm,dry}\right)\right)$	0.94	10

Notes,

cESP: cold-side Electrostatic Precipitator;

cESP/FGD: cold-side Electrostatic Precipitator with wet Flue Gas Desulphurization;

hESP: hot-side Electrostatic Precipitator;

hESP/FGD: hot-side Electrostatic Precipitator with wet Flue Gas Desulphurization;

SDA/FF: Spray Dry Adsorption with Fabric Filter.

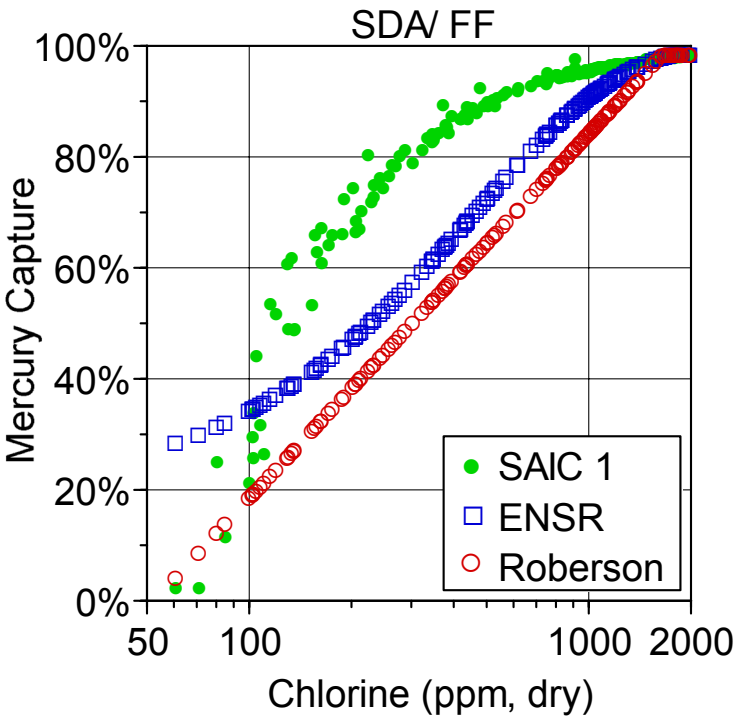

Figure 2. Three equations predict different amounts of mercury capture for SDA/FF technology when applied to data for 161 U.S. counties.

Notes, SDA/FF: Spray Dry Adsorption, Fabric Filter; SAIC (2003), ENSR (2003), and Roberson (2002) equations listed on table 2 (this report); ICR 2 county-average coal assay data (appendix); results for six counties with >2000 ppm chlorine and one county with <50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.

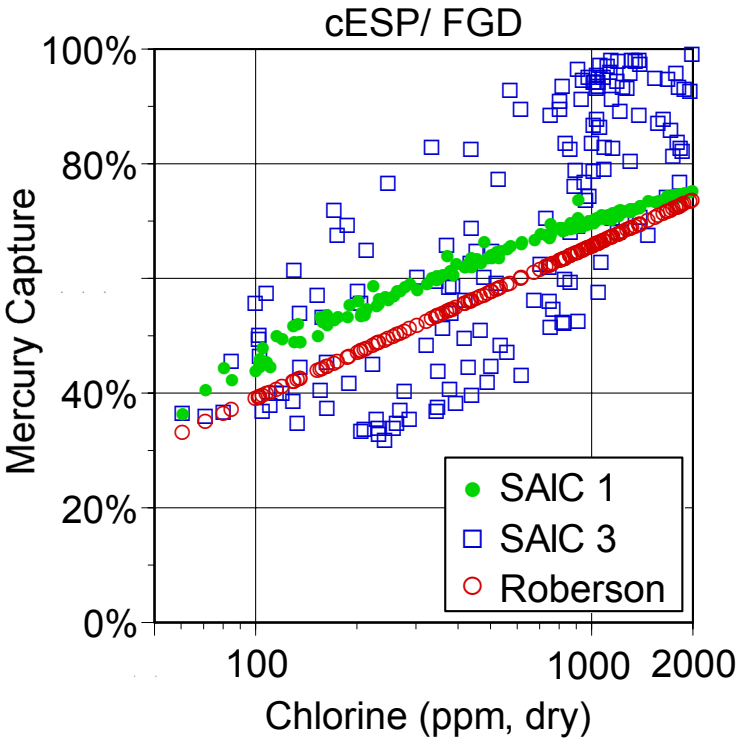

Figure 3. Three equations predict different amounts of mercury capture for cESP/FGD technology when applied to data for 161 U.S. counties.

Notes, cESP/FGD: cold-side Electrostatic Precipitator, wet Flue Gas Desulphurization; SAIC (2003), and Roberson (2002) equations listed on table 2 (this report); ICR 2 county-average coal assay data (appendix); results for six counties with >2000 ppm chlorine and one county with < 50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.

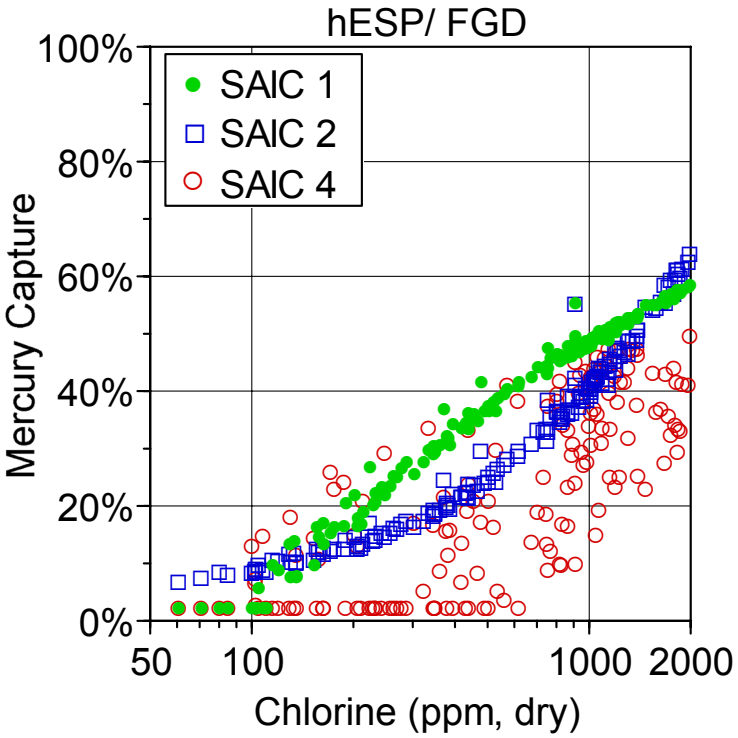

Figure 4. Three equations predict different amounts of mercury capture for hESP/FGD technology when applied to data for 161 U.S. counties.

Notes, hESP/FGD: hot-side Electrostatic Precipitator, wet Flue Gas Desulphurization; SAIC (2003) equations listed on table 2 (this report); ICR 2 county-average coal assay data (appendix); results for six counties with >2000 ppm chlorine and one county with < 50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.

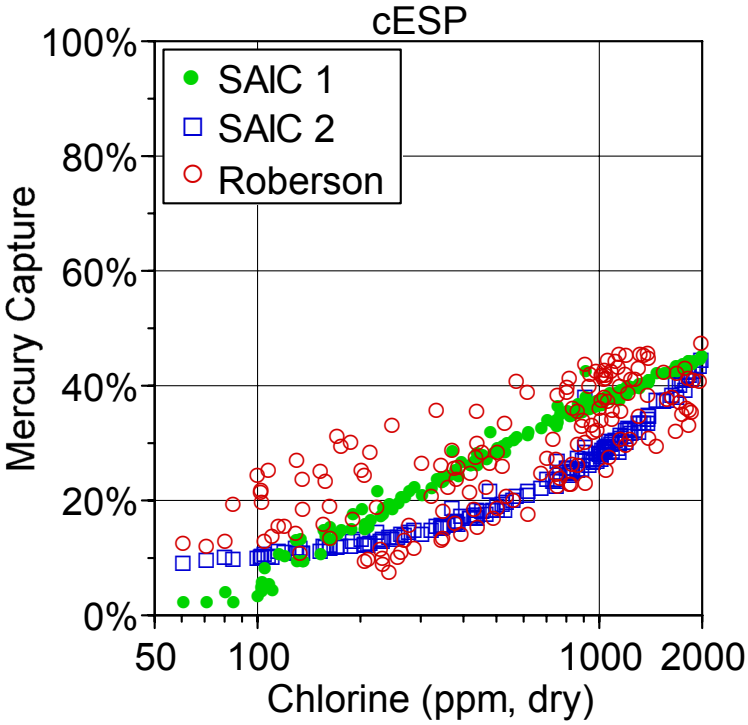

Figure 5. Three equations predict different amounts of mercury capture for cESP technology when applied to data for 161 U.S. counties.

Notes, cESP: cold-side Electrostatic Precipitator; SAIC (2003), and Roberson (2002) equations listed on table 2 (this report); ICR 2 county-average coal assay data (appendix); results for six counties with >2000 ppm chlorine and one county with < 50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.

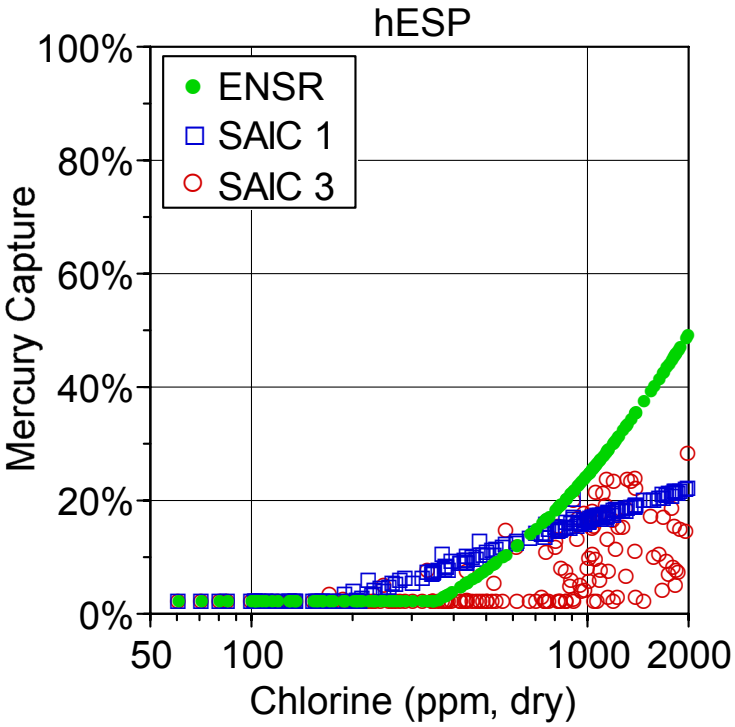

Figure 6. Three equations predict different amounts of mercury capture for hESP technology when applied to data for 161 U.S. counties.

Notes, hESP: hot-side Electrostatic Precipitator; ENSR (2003) and SAIC (2003) equations listed on table 2 (this report); ICR 2 county-average coal assay data (appendix); results for six counties with >2000 ppm chlorine and one county with <50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.

The similar statistical significance but different county-specific results for the equations listed in table 2, coupled with the lack of a verification data set, makes selection of the best equation for each technology group largely arbitrary. Lacking objective criteria to select a single best equation, we chose to use the average result obtained from all three equations.

As might be expected, using the average result from three equations (rather than just one), adding data for more counties, and correcting erroneously low-mercury values for Gulf Coast coal, changed the maps being made for this project. Figures 7 through 16 show the revised draft maps, which more closely correspond to the final maps that are currently being constructed.

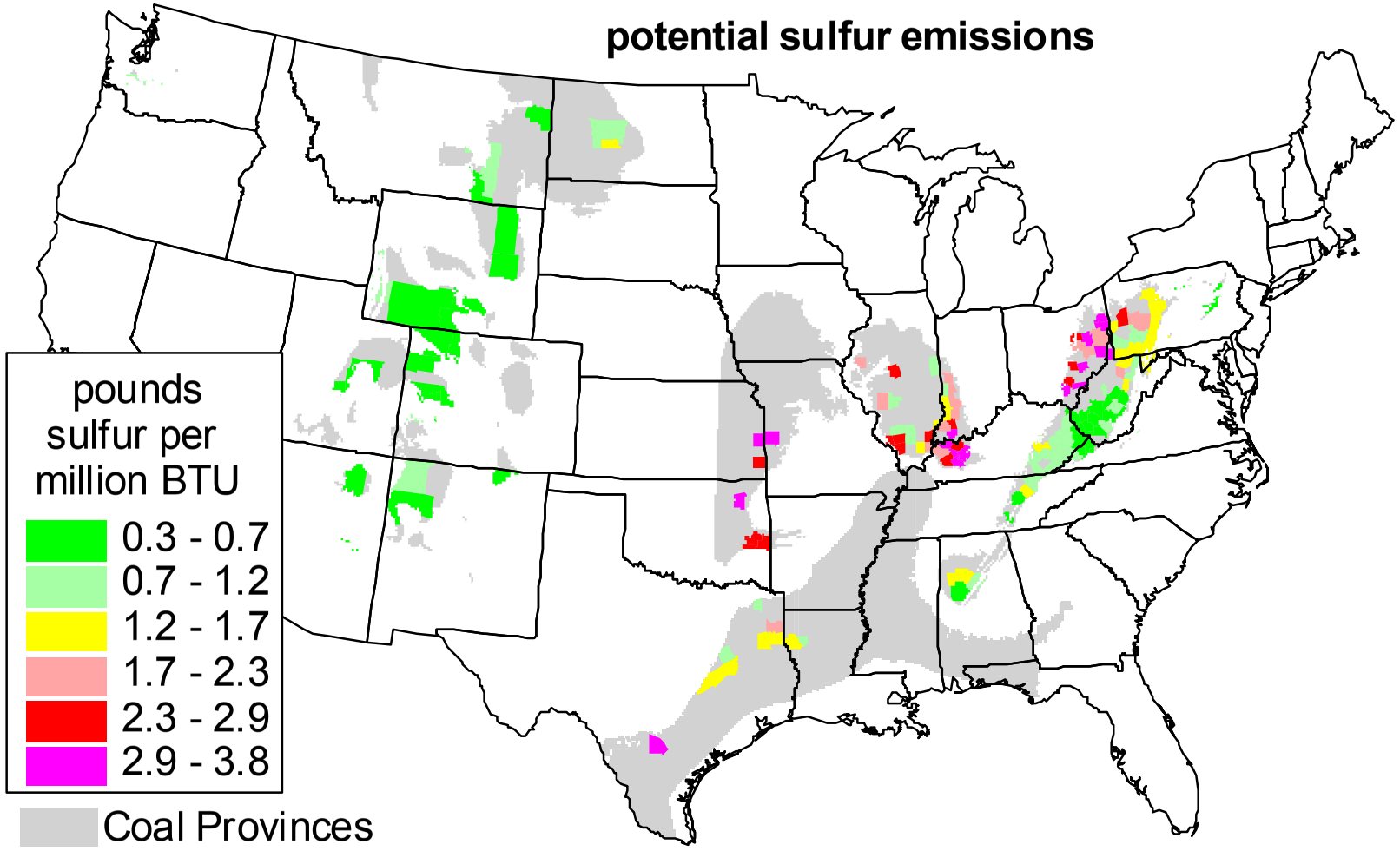

Figure 7. Potential uncontrolled sulfur emissions from coal (lbs S/10^6 Btu) by U.S. county-of-origin (county-average values calculated using selected ICR data).

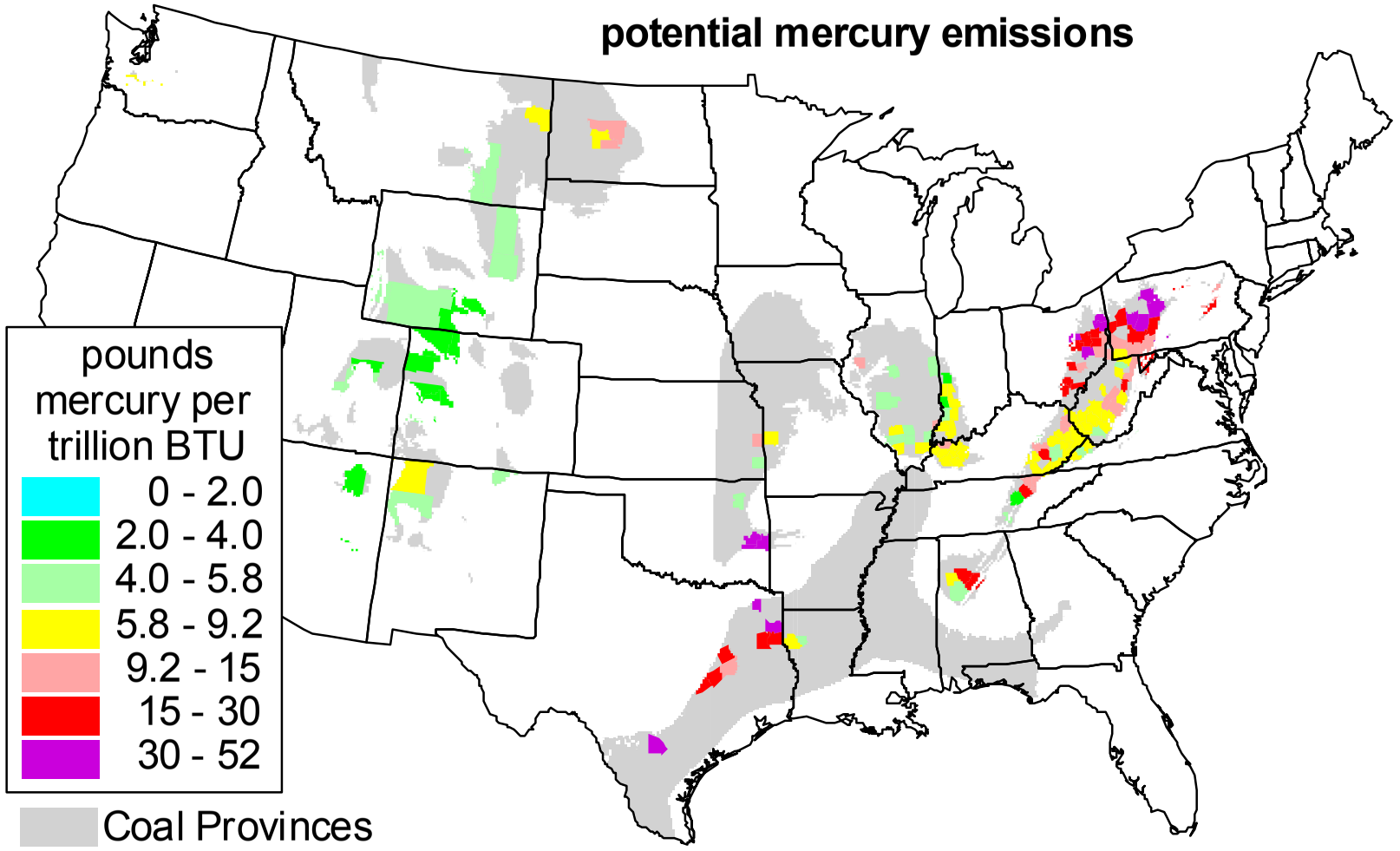

Figure 8. Potential uncontrolled mercury emissions from coal (lbs Hg/10^{12} Btu) by U.S. county-of-origin (county-average values calculated using selected ICR data).

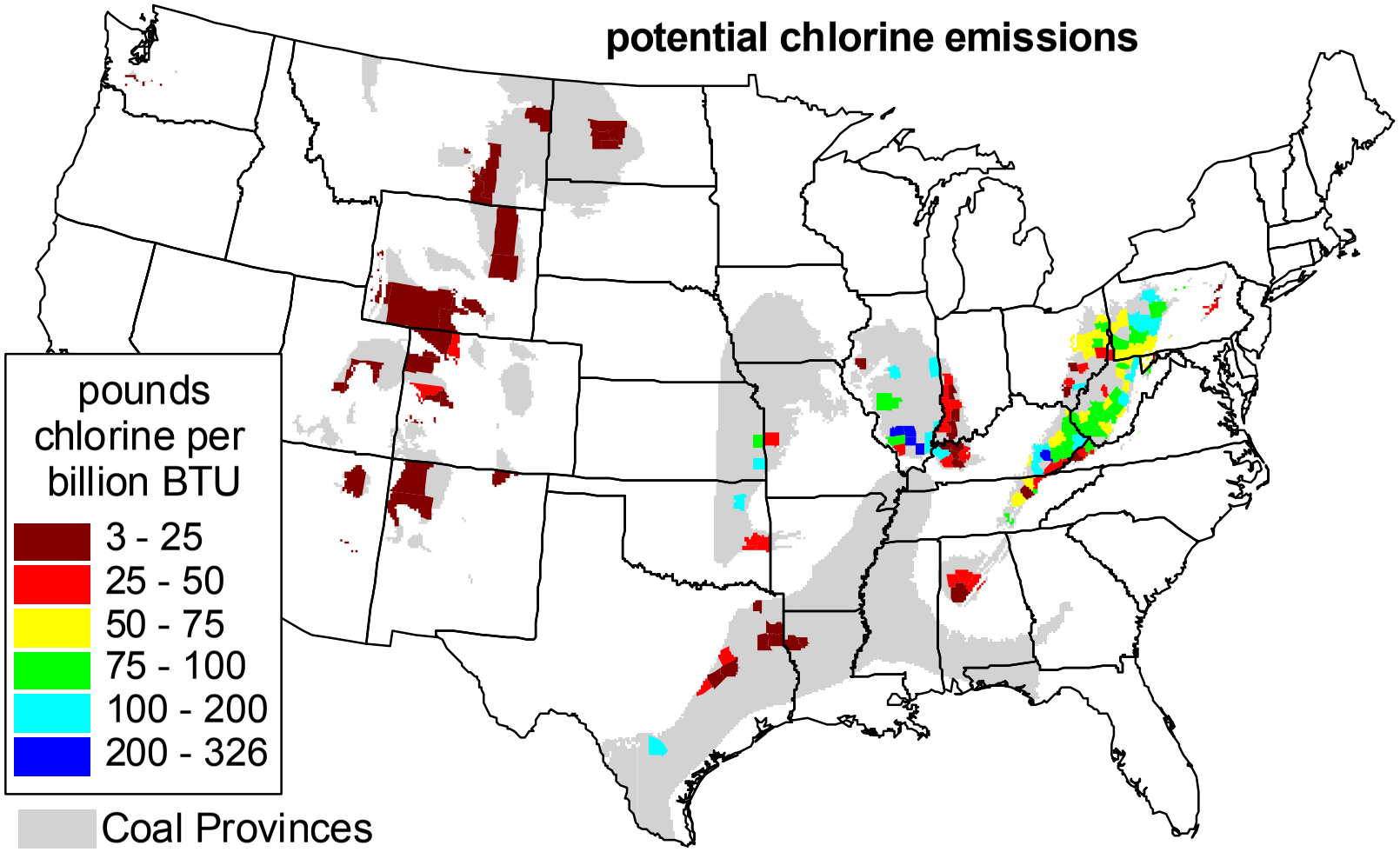

Figure 9. Potential uncontrolled chlorine emissions from coal (lbs Cl/10^9 Btu) by U.S. county-of-origin (county-average values calculated using selected ICR data).

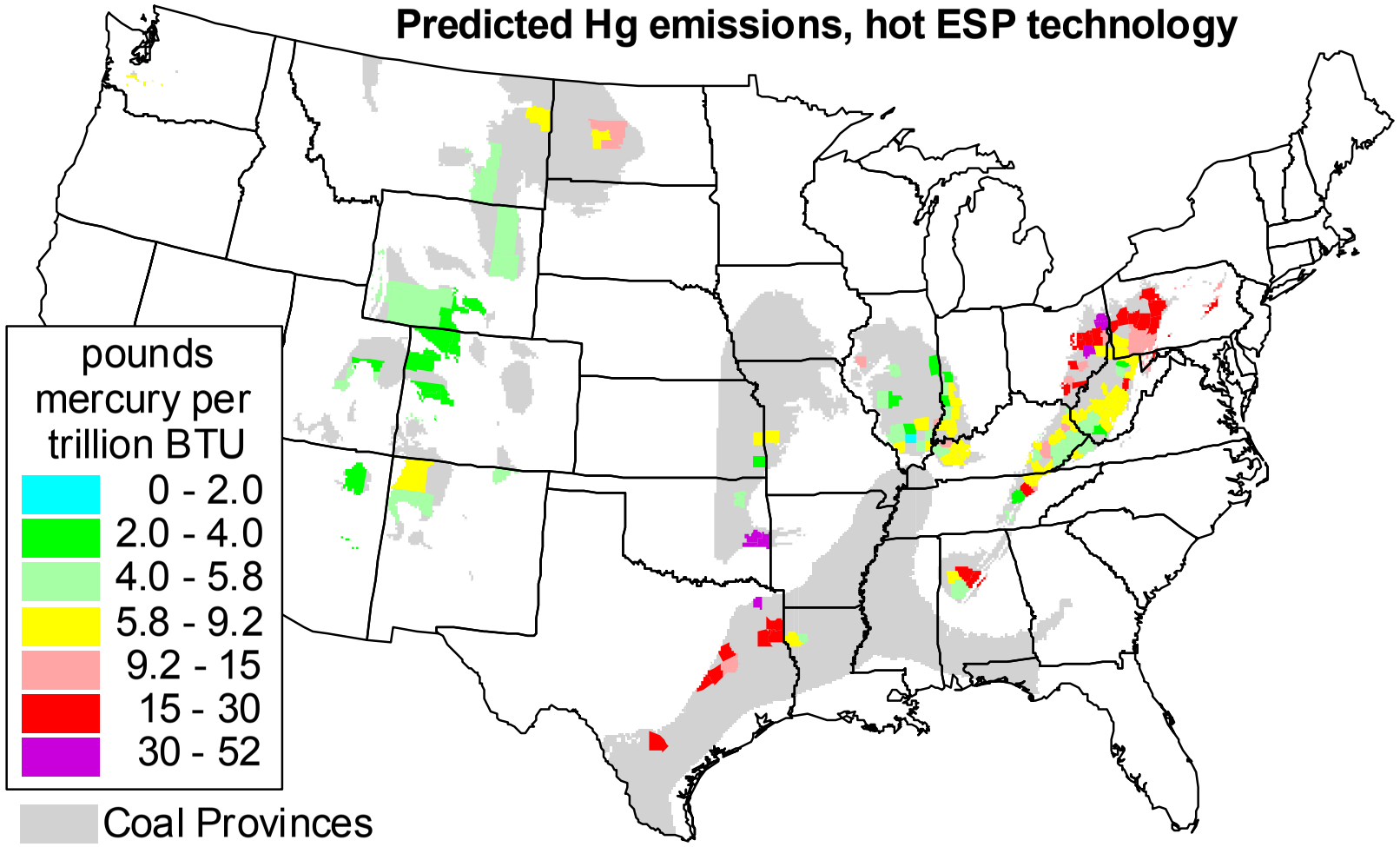

Figure 10. Predicted mercury emissions (lbs Hg/10^{12} Btu) for coal burned in electric utilities with Hot-Side, Electrostatic Precipitators (hot ESP technology). Shown are county-average values calculated using selected ICR data and equations listed in table 2, this report.

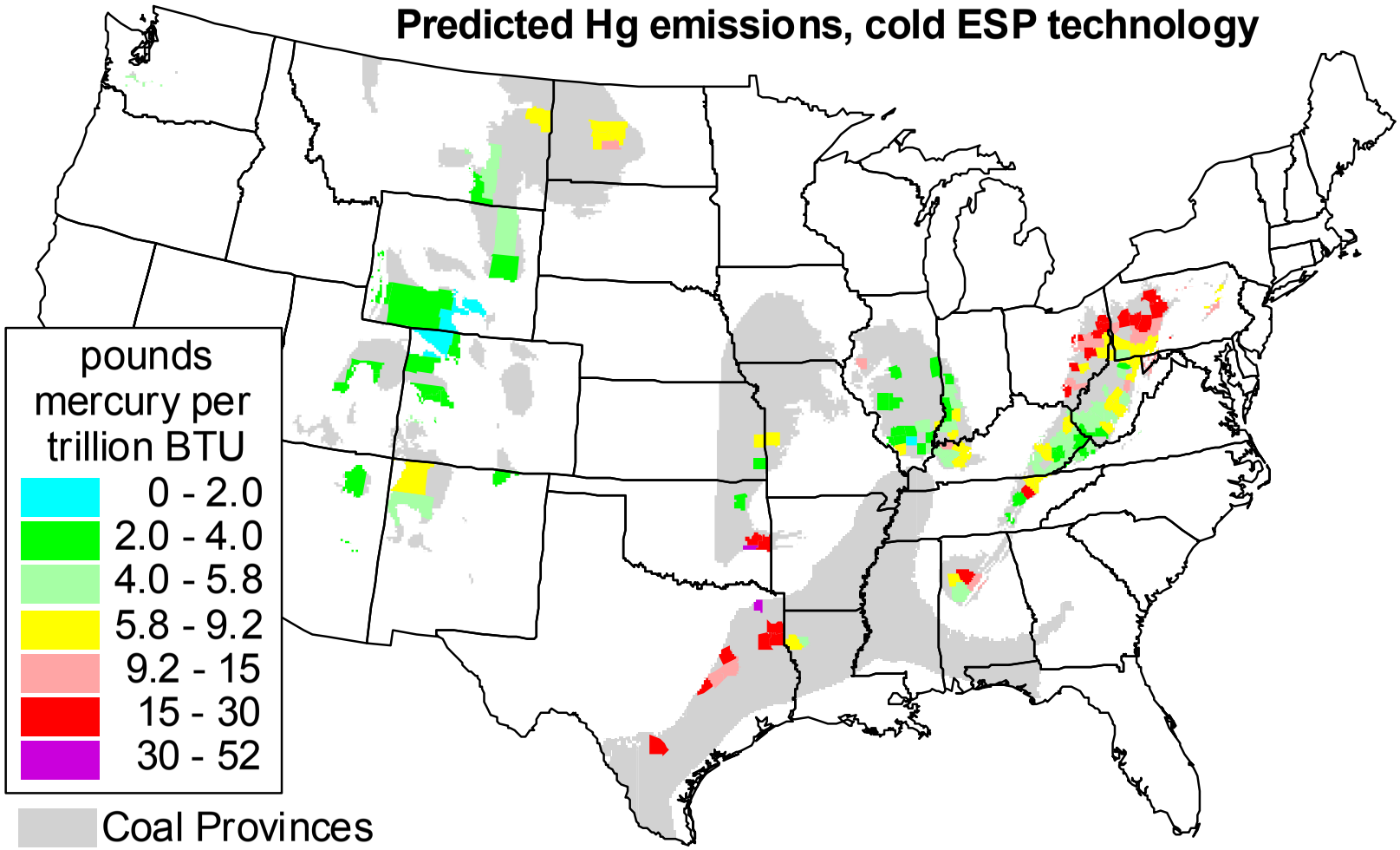

Figure 11. Predicted mercury emissions (lbs Hg/10^{12} Btu) for coal burned in electric utilities with Cold-Side, Electrostatic Precipitators (cold ESP technology). Shown are county-average values calculated using selected ICR data and equations listed in table 2, this report.

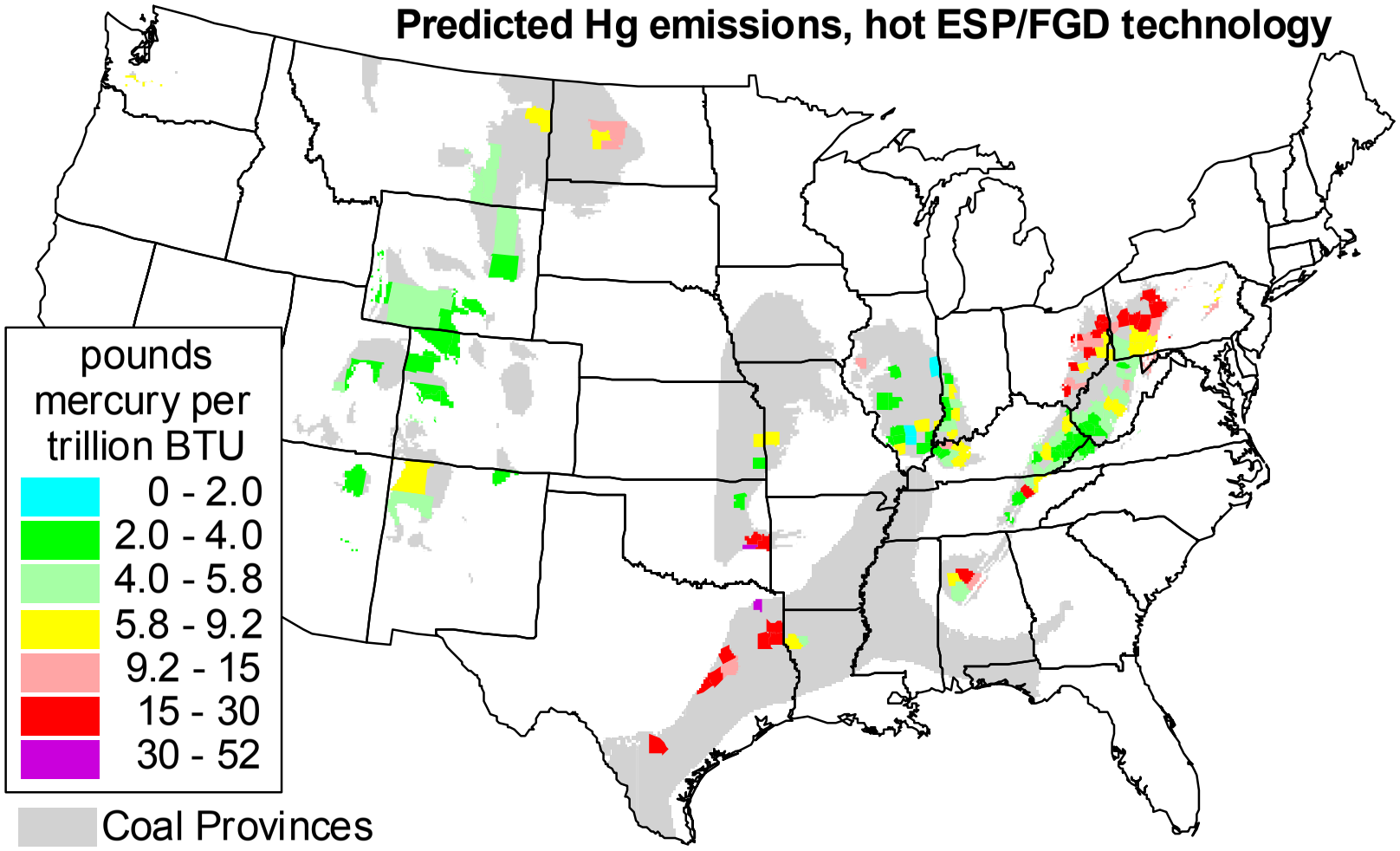

Figure 12. Predicted mercury emissions (lbs Hg/10^{12} Btu) for coal burned in electric utilities with Hot-Side, Electrostatic Precipitators and wet Flue Gas Desulphurization controls (hot ESP/FGD technology). Shown are county-average values calculated using selected ICR data and equations listed in table 2, this report.

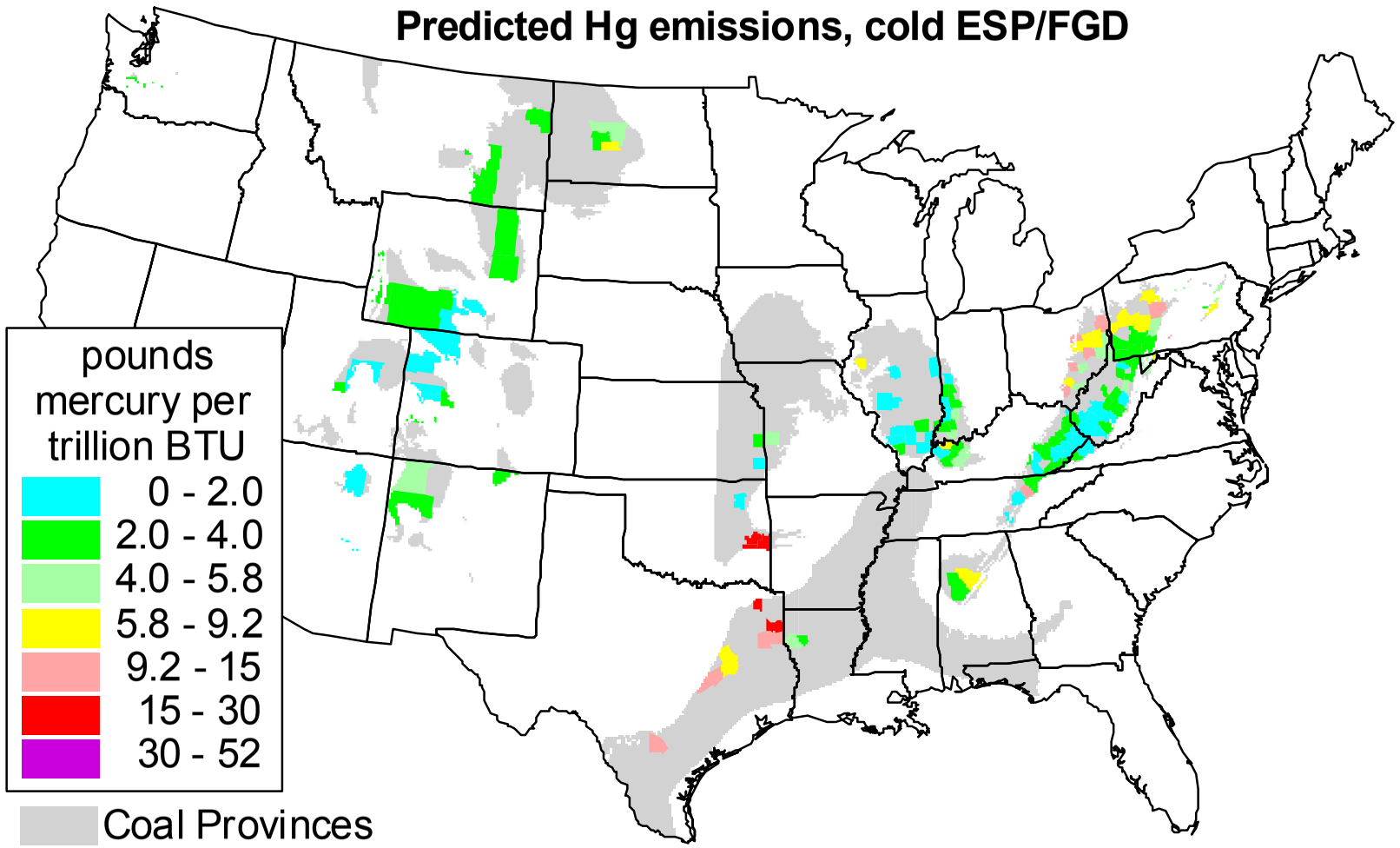

Figure 13. Predicted mercury emissions (lbs Hg/10^{12} Btu) by U.S. county-of-origin for coal burned in electric utilities with Cold-Side, Electrostatic Precipitators and wet Flue Gas Desulphurization controls (cold ESP/FGD technology). Shown are county-average values calculated using selected ICR data and equations listed in table 2, this report.

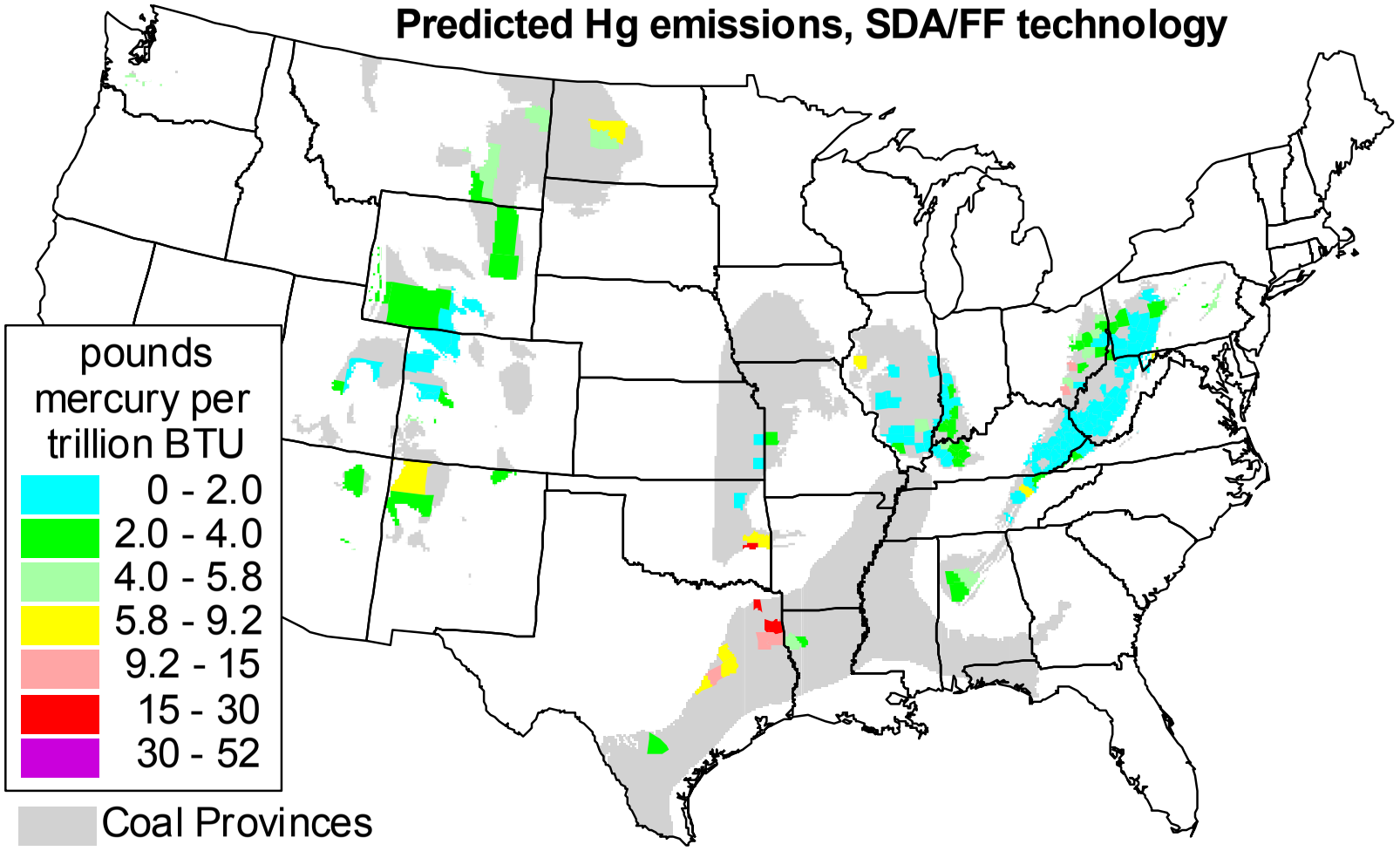

Figure 14. Predicted mercury emissions (lbs Hg/10^{12} Btu) by U.S. county-of-origin for coal burned in electric utilities with Spray-Dry Adsorption and Fabric Filter controls (SDA/FF technology). Shown are county-average values calculated using selected ICR data and equations listed in table 2, this report.

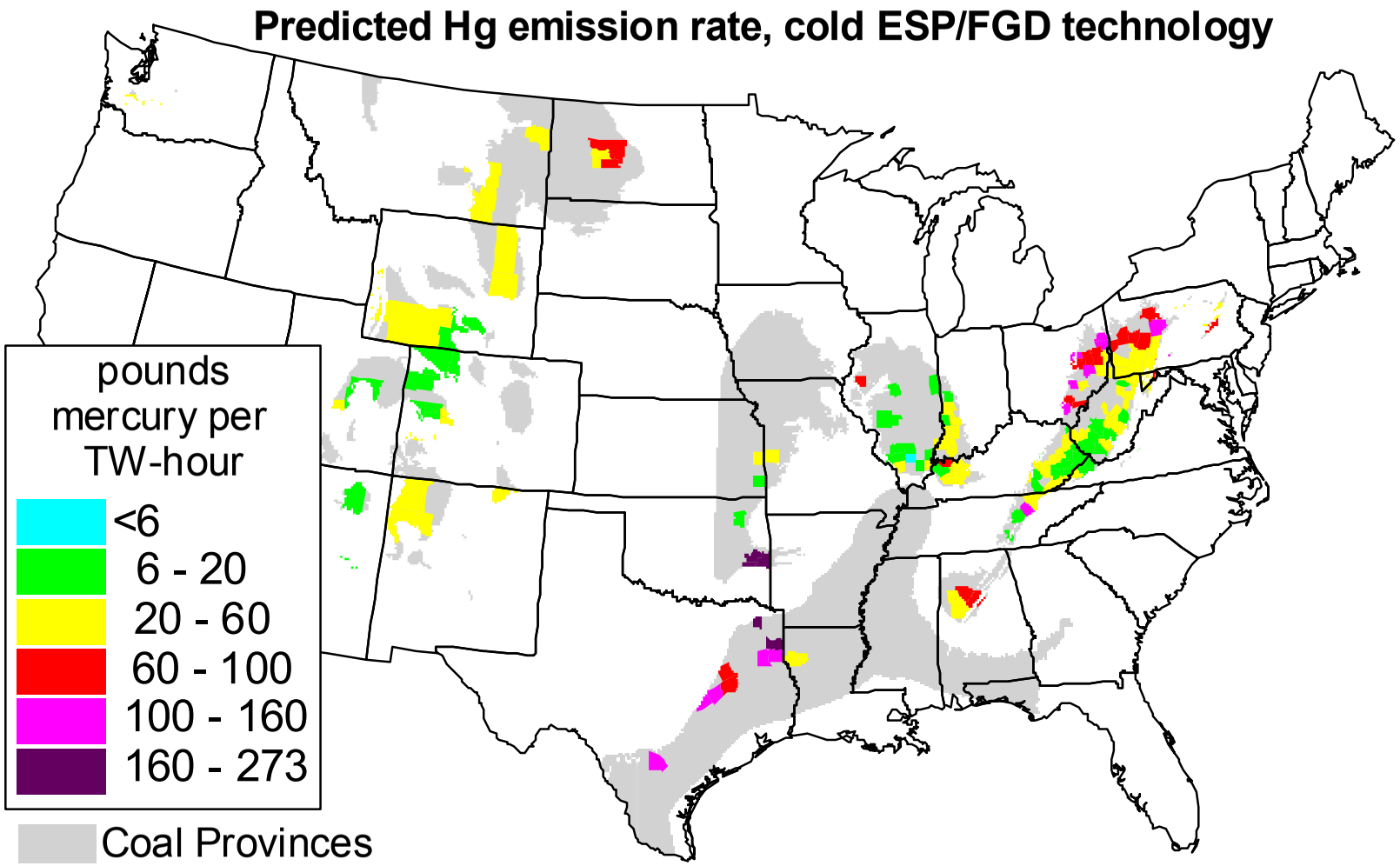

Figure 15. Predicted mercury emission rate (lbs Hg/terawatt-hour, which is the same as lbs Hg x 10^{-6}/megawatt-hour) for coal burned in electric utilities with Cold-Side, Electrostatic Precipitators and wet Flue Gas Desulphurization controls (cold ESP/FGD technology). Shown are county-average values calculated using selected ICR data expressed on a net energy basis, a nominal heat rate of 35%, and equations listed in table 2, this report.

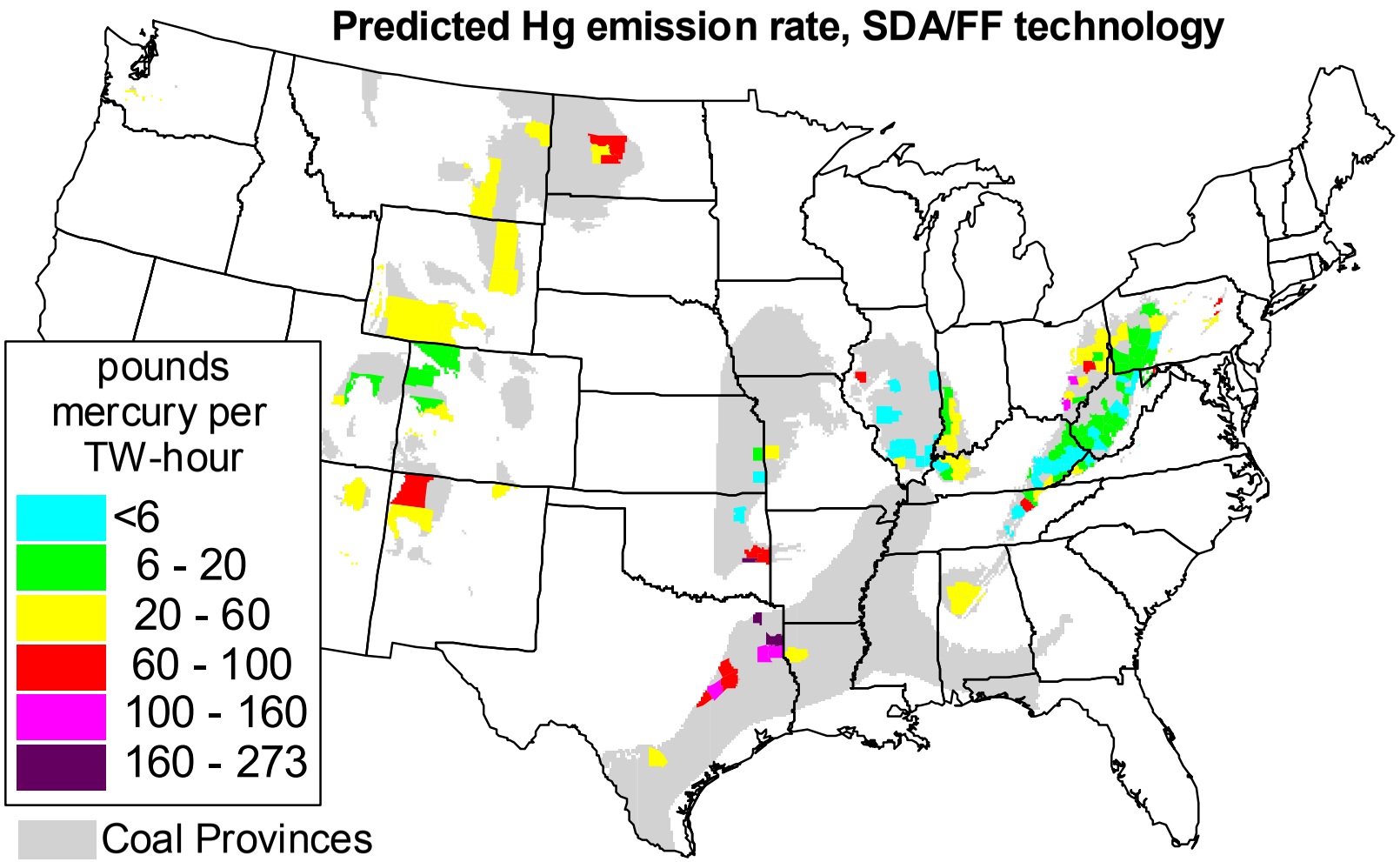

Figure 16. Predicted mercury emission rate (lbs Hg/terawatt-hour, which is the same as lbs Hg x 10^{-6}/megawatt-hour) for coal burned in electric utilities with Spray-Dry Adsorption and Fabric Filter controls (SDA/FF technology). Shown are county-average values calculated using selected ICR data expressed on a net energy basis, a nominal heat rate of 35%, and equations listed in table 2, this report.

RESULTS AND DISCUSSION

Revised draft maps showing the potential mercury and acid-gas emissions from coal combustion by U.S. county-of-origin were made using selected ICR 2 coal quality data, and the average result from three, technology-specific equations that predict mercury capture (table 2). This section discusses the decision to use the average result from three equations (rather than just one) as well as strategies to reduce mercury emissions using existing technology. We also examine the effectiveness of existing technologies to control mercury emissions, and consider why coal sulfur appears to reduce mercury capture. Finally, we examine the significance and potential of pre-combustion controls to reduce mercury emissions.

Selecting the Best Equation to Predict Mercury Capture

Table 2 lists three equations that predict mercury capture for each of five different existing control technologies. The equations were all derived by regression analysis on the ICR 3 stack emission data (USEPA, 2003), and use various measures of coal quality (chlorine, Btu, and sulfur values) as independent variables. Although the technology-specific equations show similar correlations and trends, results sometimes differ when they are applied to the same county-average coal quality values. Lacking objective criteria to select a single best equation from those listed in table 2, we used the average result obtained from all three equations.

Clearly, our decision to use all three equations, rather than just one, could be considered arbitrary. However, using three equations should reduce extrapolation error when an equation is applied to assay values that are outside the range of ICR 3 values that these regression equations were made from. For example, figure 6 shows that the different equations predict substantially different results for high-chlorine coal burned units with hESP technology. With one exception (Cliffside unit 1), relatively low-chlorine coal was burned in ICR 3 units equipped with this

technology. Consequently, the validity of the hESP-specific equations is uncertain for high-chlorine coal. Nonetheless, given the divergent results for high-chlorine coal shown in figure 6, using the average result from all three equations clearly avoids large errors necessarily associated with at least one of the equations.

Admittedly, there are other useful and significant equations that are not included in table 2 (Chu and others, 2000; Laumb and other 2000; AEMS 2004). However, the selection of equations for table 2 was not wholly arbitrary. The selection was instead a compromise that required similar technology classes, and favored high r^2 values, diverse authorship, and different independent variables. Selecting three (rather than two, four, or more) equations for each technology group was likewise a compromise. This convention simplified spreadsheet calculations and allowed for the inclusion of convex, concave, and linear equation forms.

Comparison of Existing Technologies: Implications for Mercury Control

Figure 17 compares the average technology-specific mercury capture calculated for 162 U.S. counties using the three equations listed in table 2 for each technology control class. Note that mercury capture increases as coal chlorine increases for each control technology. This trend is particularly noteworthy for SDA/FF and cESP/FGD technologies, where capture rapidly increases up to about 500 ppm chlorine, but only modestly increases above 1000 ppm chlorine. Thus, blending a low-chlorine coal with a high-chlorine coal to an optimum level between 500 and 1000 ppm chlorine, should result in a net reduction of mercury emissions for coal burned in units equipped with SDA/FF or cESP/FGD emission controls.

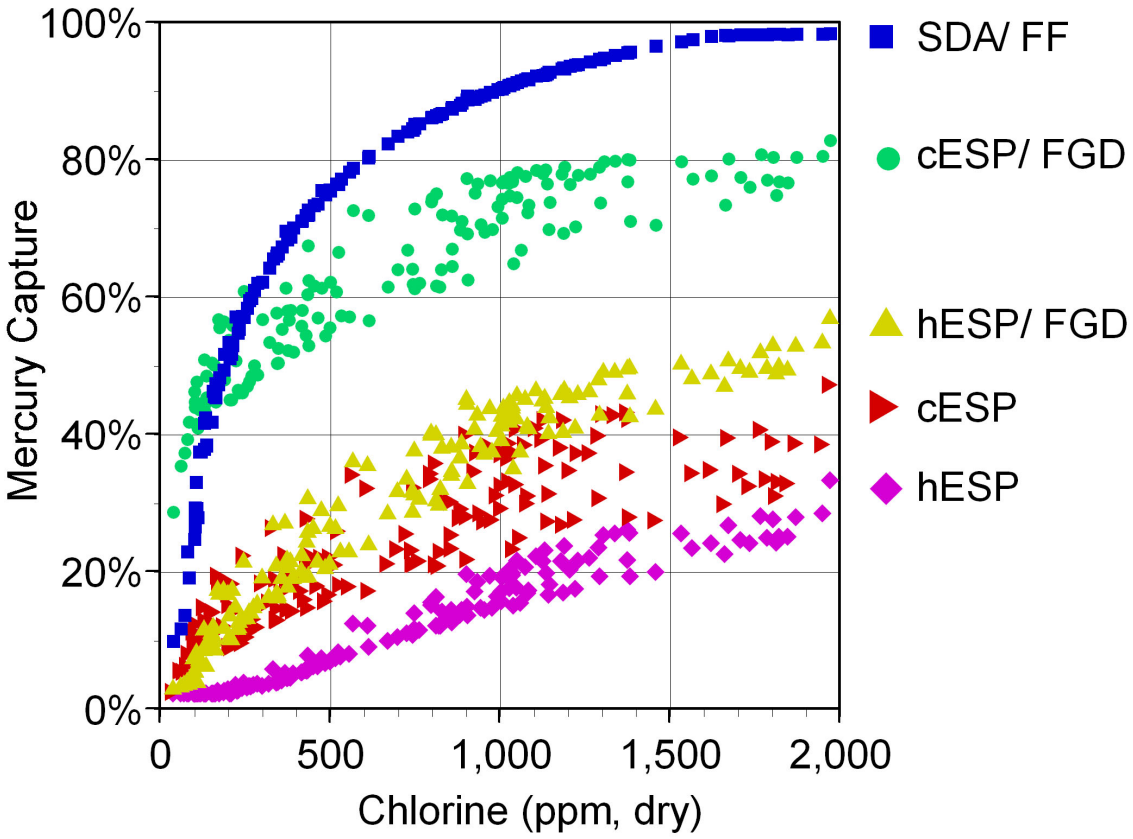

Figure 17. Mercury capture predicted for 162 U.S. counties increases with increasing coal chlorine for five existing control technologies. Mercury capture is the average result of three equations for each control technology applied to county-average, ICR 2 coal assay values. The equations are listed in table 2 (this report); county-average ICR 2 assay values are listed the appendix.

Units equipped with hESP/FGD, cESP/FGD or hESP emission controls show relatively poor mercury capture. Absent effective mercury-specific controls, selection of low-mercury coal would be a good mercury control strategy for these units.

Weighting the county-specific results shown in figure 17 by county production tonnage allows calculation of the average mercury emissions, together with the average percent reduction, for each post-combustion technology. Likewise, the effectiveness of pre-combustion technology can be calculated by comparing in-ground coal mercury with commercially shipped

coal mercury and weighting the results by county production. Table 3 shows the results of these calculations.

Table 3. Comparison of mercury control technologies, by U.S. county-of-origin.

	Technology	Trillion Btu [1]	lbs Hg/10^{12} Btu	% Mercury Reduction
Pre-Combustion	None (In-ground coal, COALQUAL data) [2]	—	~ 11.0	—
	Counties with no mercury reduction (ICR 2 data)	5,931	11.2	—
	Washing/Mining Practice (ICR 2 data) [3]	11,335	6.3	~ 57%
	No data (counties without COALQUAL or ICR 2 data)	1,809	?	?
Post-Combustion	None (delivered coal)	19,047	8.3	—
	hESP	1,769	7.5	9%
	cESP	10,260	6.3	24%
	hESP/FGD	565	6.2	25%
	cESP/FGD	3,579	3.4	59%
	SDA/FF	511	3.1	63%

[1] Amount of coal, expressed as coal Btu content; post-combustion values from Chu and others (2000).

[2] The 11 lb Hg/10^{12} Btu value for the total U.S. in-ground coal resource was calculated using state-average COALQUAL Hg values, and weighting by estimated coal resource (tonnage) values from the USEIA (2000) 1997 vintage, demonstrated reserve base. This value (and the derived 57% mercury reduction due to washing and mining practice) will likely change when the demonstrated reserve base estimate is updated.

[3] Counties where the mercury content of the in-ground coal is more than 2 lbs Hg/10^{12} Btu greater than the mercury content of commercial coal shipped from that county.

Several caveats apply to table 3. First, mercury reductions listed for cESP/FGD and SDA/FF technologies are likely minimum values because they indicate the fractional emissions expected if all U.S. coal were burned in these technology classes, rather than the coals that are currently burned. Many of these units burn coal blends originating from several counties. As

noted above, the optimal mercury capture for these technologies occurs where the coal contains between 500 and 1000 ppm chlorine. Given that the tonnage-weighted average chlorine content of U.S. coal is ~530 ppm, coal blends are more likely to approach this optimal value than single-sourced coal.

Table 3 shows that in-ground U.S. coal contains about 11 lbs $Hg/10^{12}$ Btu. This value is less certain than the mercury content of coal delivered to power plants during 1999 included in the ICR 2 data set. For example, weighting COALQUAL mercury values aggregated by U.S. state (excluding Alaska), by the USEIA (2000) Demonstrated Reserve Base tonnage estimates for these states shows an average 10.8 lbs Hg/1012 Btu. However, where average COALQUAL mercury values for counties listed in the ICR data set are weighted by coal production tonnage, the result is 11 lbs $Hg/10^{12}$ Btu.

Another limitation of values listed in table 3 relates to the likely co-reduction of coal sulfur due to coal mining and coal washing practice. As noted below, coal sulfur decreases post-combustion mercury capture. Consequently, the technology-specific, post-combustion mercury reductions listed in table 3 may increase if the sulfur content of commercial U.S. coal continues to decline (Quick and others, 2004).

The Relationship Between Coal Sulfur and Mercury Capture

Figure 17 shows that mercury emissions from SDA/FF controls are exclusively correlated with chlorine whereas mercury emissions predicted for the other technologies are more variable. The scatter shown in figure 17 for cESP/FGD, hESP/FGD, cESP, and hESP technologies is attributed to coal sulfur, which is a factor in one or more of the respective equations for these technologies (table 2), but not used in the SDA/FF equations. Notably, in every equation where

sulfur is an independent variable (table 2), mercury capture is predicted to decline with increasing coal sulfur.

The equations listed in table 2 clearly show the consistently negative effect of coal sulfur on mercury capture. The explanation for this effect is less obvious. Hocquel and others (2001) offer two explanations for the negative effect of sulfur on mercury capture; both reduce the amount of Cl_2 available for mercury oxidation. The first inhibits the heterogeneous conversion of HCl to reactive Cl_2 by sulfation of metal oxides that would otherwise catalyze this conversion. The second indicates that gaseous SO_2 in the presence of water vapor can homogenously reduce Cl_2 to less-reactive HCl and by-product SO_3. A mechanistic model for mercury capture by fly-ash carbon (Olson and others 2003) suggests that sulfuric acid (from oxidation of flue-gas SO_2) limits mercury capture by filling Hg binding/reaction sites on the carbon surface.

Alternately, the negative effect of coal sulfur on mercury capture may simply relate to higher flue-gas temperatures required to avoid corrosion of the ductwork from H_2SO_4 when burning high-sulfur coal. Meij and others (2002) attribute the greater mercury capture by ESP controls on power plants in the Netherlands, compared to those in Germany and the U.S., to lower flue-gas ESP temperatures in the Netherlands power plants (~120 ºC), which burn comparatively low-sulfur coal. The median temperature for cold-side ESP units included in the ICR 3 data set of U.S. power plants is about 160 ºC, whereas Meij and others (2002) suggest that oxidized mercury, present as $HgCl_2$, does not condense on fly ash above about 140 ºC.

Empirical data from Canadian Electricity Association members (CEA, 2004) also show a negative correlation between coal sulfur on mercury capture. The relationship (figure 18) is strongest where fly-ash carbon exceeds five percent (and chlorine is coincidentally high). This relationship is consistent with the mechanistic model suggested by Olson and others (2003)

where sulfur fills reactive sites on fly-ash carbon. Their explanation may also explain why sulfur is not a significant predictor of mercury capture for units equipped with SDA/FF technology; in this instance, gaseous flue-gas sulfur is converted to a non-reactive solid (sulfate) before it arrives at the particulate filter, where effective mercury capture by fly-ash carbon presumably occurs.

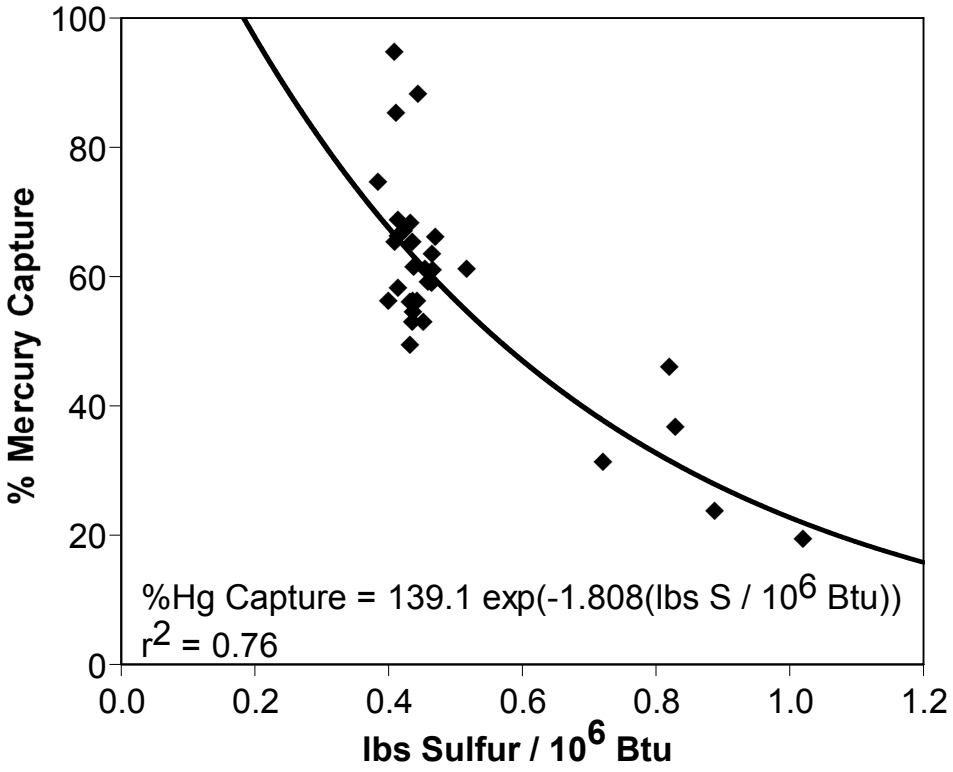

Figure 18. Decreasing mercury capture with increasing coal sulfur. Data points show weekly averages (CEA, 2004) observed for two units equipped with cESP emission controls where fly-ash carbon exceeds 5% (average 11%). Mercury capture was estimated after Meij and others (2002) using coal and fly-ash mercury values, and assuming an 80:20, fly ash:bottom ash fractionation. Two data points greater than 100% capture are not shown.

In this section we have suggested that mercury capture by carbon in fly ash may be improved by reducing the amount of sulfur in the feed coal. This effect complements the likely reduction of mercury in the coal when the sulfur content of coal is reduced (Quick and others,

2003). Thus, selection of low-sulfur coal has two likely effects: (1) reducing the amount of mercury in the feed coal, and (2) improving post-combustion mercury capture.

In-Ground Coal Mercury Compared to Commercial Coal Mercury

Direct comparison of COALQUAL data records (in-ground coal) with ICR 2 data records (commercial coal) showed that coal delivered to utilities during 1999 has about half as much mercury as the in-ground coal resource (Quick and others, 2003). This difference was attributed to preferential mining of relatively low-mercury coal, and coal washing. Toole-O'Neil and others (1999) note that washing reduces coal mercury levels by about 35%. Restricting the comparison to counties where both COALQUAL and ICR data are available, and weighting the county-average mercury values by coal production tonnage, shows that the in-ground coal resource averages about 11 lbs $Hg/10^{12}$ Btu, whereas commercial coal deliveries during 1999 averaged about 8.3 lbs $Hg/10^{12}$ Btu. Perhaps more significantly, this difference is not geographically uniform. For example, figure 19 shows that coal produced from the northern Appalachians and Gulf Coast regions typically has more mercury than expected from the mercury content of the in-ground coal. The reason for these increased mercury levels is uncertain. Possibly, the increased mercury levels result from dilution of mined coal with either surrounding, high-mercury country rock or included, high-mercury rock partings. If so, coal washing or selective mining might be effective mercury reduction strategies in these areas.

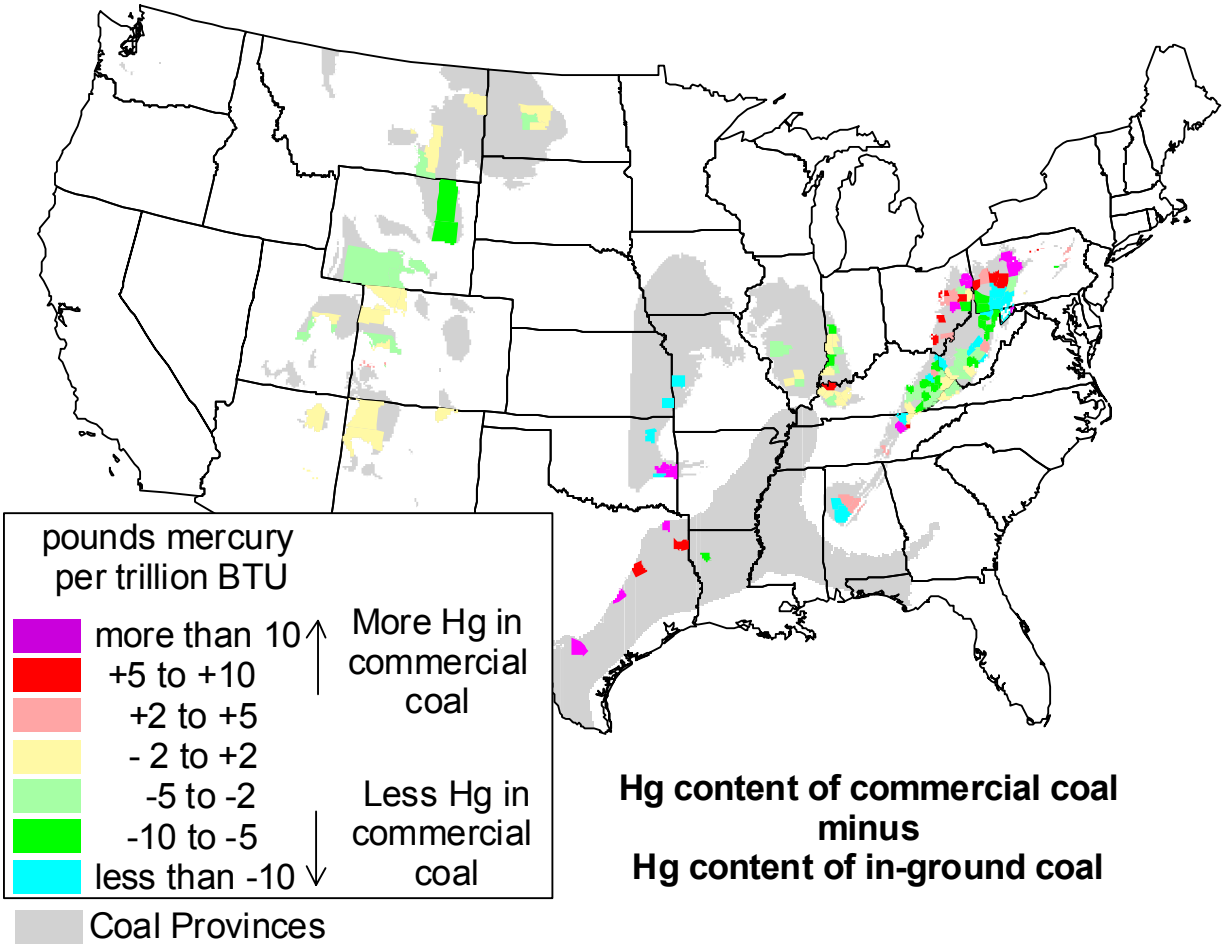

Figure 19. Commercial coal from some areas has more mercury than what might be expected based on in-ground coal assays (COALQUAL data). Although the mercury content of commercial coal delivered to utilities during 1999 (ICR 2 data) was about 25% less than the actively mined, in-ground coal resource (COALQUAL data), this difference is not geographically consistent.

Areas where mined coal contains more mercury than the in-ground coal may be good places to consider pre-combustion mercury reduction strategies. Comparing the mercury content of mined coal with the mercury content of in-ground coal has more immediate significance because it shows the significance of pre-combustion mercury reduction strategies (selective mining and coal washing). Indeed, the mercury content of U.S. coal delivered to the power plant

during 1999 contained, on average, 2.8 lbs Hg/10^{12} Btu less mercury than the in-ground coal resource. This 25% mercury reduction is significant.

CONCLUSIONS

We have revised draft maps showing potential sulfur, chlorine, and mercury emissions for U.S. coals by county-of origin, and have begun construction of the final maps. Although county-average ICR 2 mercury values for most Gulf Coast coal have been increased (in recognition of systematic assay errors), mercury values for Leon County Texas, as well as DeSoto and Red River Parishes Louisiana, have not been adjusted and are probably too low. Results from this reporting period suggest the following:

- Selection of coal with low mercury content may be an effective control strategy for units equipped with hESP/FGD, cESP, or hESP controls, whereas selection of high-chlorine coal is indicated for units with cESP/FGD or SDA/FF controls.
- Blending to an optimum level between 500 and 1000 ppm chlorine may be an effective mercury control strategy for units equipped with SDA/FF or cESP/FGD controls.
- Flue-gas sulfur may reduce mercury capture by carbon in fly ash.
- Coal washing or selective mining might be an effective mercury reduction strategy, especially for coals from the northern Appalachians or Gulf Coast.

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APPENDIX

Summary of ICR 2 data

Coal Origin, Assay Frequency, and Production Tonnage				Average Assay Values						Mercury Capture (100% capture = 1)				
State	County	Count	Tons	Btu (moist)	%Ash (moist)	%Sulfur (moist)	%Moisture	Cl ppm (dry)	Hg ppm (dry)	hESP	cESP	hESP /FGD	cESP /FGD	SDA /FF
Alabama	Fayette	25	1,603,575	12,028	12.5	1.7	7.1	358	0.099	0.04	0.21	0.19	0.55	0.67
Alabama	Jefferson	113	6,872,058	12,257	12.7	1.3	6.6	374	0.217	0.04	0.22	0.22	0.58	0.68
Alabama	Tuscaloosa	64	3,630,889	12,558	12.1	0.8	7.5	204	0.068	0.02	0.17	0.14	0.52	0.51
Alabama	Walker	46	1,077,252	11,904	13.7	1.8	6.2	517	0.267	0.07	0.25	0.27	0.60	0.76
Arizona	Navajo	98	12,621,600	10,495	8.4	0.5	14.7	101	0.038	0.02	0.12	0.06	0.44	0.27
Colorado	Delta	34	1,152,040	12,052	7.0	0.4	8.4	99	0.035	0.02	0.12	0.08	0.46	0.24
Colorado	Gunnison	194	5,637,241	11,736	8.9	0.5	8.8	102	0.049	0.02	0.12	0.06	0.44	0.26
Colorado	Mesa	39	625,837	11,238	12.8	0.5	9.1	567	0.039	0.12	0.31	0.36	0.72	0.78
Colorado	Moffat	173	6,606,747	10,326	5.9	0.4	17.1	186	0.031	0.02	0.19	0.17	0.56	0.49
Colorado	Montrose	46	359,400	10,783	19.9	0.8	5.8	70	0.061	0.02	0.08	0.04	0.37	0.13
Colorado	Rio Blanco	53	1,221,660	10,152	11.2	0.4	13.1	174	0.038	0.02	0.19	0.17	0.55	0.48
Colorado	Routt	238	8,506,600	11,101	9.1	0.5	11.1	331	0.038	0.06	0.25	0.27	0.65	0.65
Illinois	Franklin	44	133,576	11,790	5.8	0.9	13.5	4,446	0.060	0.55	0.59	0.71	0.87	0.98
Illinois	Gallatin	220	3,542,050	12,663	9.3	2.8	6.8	1,847	0.109	0.25	0.40	0.50	0.76	0.98
Illinois	Jackson	47	426,412	11,165	10.1	2.7	12.4	427	0.105	0.05	0.21	0.19	0.54	0.72
Illinois	Jefferson	139	3,353,496	12,008	6.2	1.2	11.3	3,960	0.071	0.49	0.56	0.69	0.87	0.98
Illinois	Logan	130	1,720,958	10,451	9.0	3.0	17.3	1,662	0.074	0.22	0.38	0.47	0.73	0.98
Illinois	Macoupin	192	3,562,497	10,629	8.1	2.3	16.9	1,143	0.064	0.16	0.34	0.40	0.69	0.92
Illinois	McDonough	3	67,383	12,128	5.7	2.8	11.7	209	0.193	0.02	0.12	0.10	0.45	0.51
Illinois	Montgomery	54	421,800	10,674	8.6	1.2	16.0	1,205	0.058	0.20	0.37	0.46	0.76	0.93
Illinois	Perry	187	4,261,814	11,031	9.7	2.7	12.9	1,186	0.062	0.17	0.34	0.40	0.69	0.93
Illinois	Randolph	295	139,091	10,908	10.4	3.0	12.7	1,060	0.063	0.15	0.32	0.38	0.67	0.91
Illinois	Saline	331	8,994,720	12,175	8.5	1.8	9.2	3,088	0.101	0.39	0.50	0.63	0.85	0.98
Illinois	Vermillion	74	581,427	10,849	8.8	1.3	16.1	2,561	0.054	0.36	0.49	0.61	0.84	0.98

Illinois	Wabash	54	1,274,002	11,006	10.5	1.5	13.4	1,804	0.164	0.27	0.42	0.53	0.80	0.98
Illinois	Washington	9	3,151,783	11,375	5.4	1.2	17.0	4091	0.112	0.50	0.57	0.69	0.86	0.98
Illinois	White	56	2,525,550	11,807	7.5	3.0	10.9	1,383	0.076	0.19	0.35	0.43	0.71	0.95
Indiana	Clay	4	90,700	10,429	14.7	2.2	12.9	275	0.082	0.03	0.17	0.15	0.50	0.61
Indiana	Daviess	46	3,102,043	11,318	8.8	2.6	13.5	227	0.111	0.02	0.14	0.12	0.46	0.54
Indiana	Gibson	113	7,783,831	11,210	9.0	2.2	13.5	346	0.082	0.04	0.19	0.17	0.52	0.66
Indiana	Greene	114	4,466,450	11,063	9.2	1.9	15.0	415	0.085	0.05	0.21	0.20	0.55	0.71
Indiana	Knox	259	2,924,700	11,196	8.7	1.5	14.3	416	0.062	0.05	0.22	0.23	0.58	0.71
Indiana	Parke	46	111,200	11,986	6.5	2.1	11.7	463	0.055	0.06	0.22	0.22	0.57	0.73
Indiana	Pike	161	4,334,497	11,397	9.3	3.1	12.1	230	0.084	0.02	0.13	0.12	0.46	0.55
Indiana	Sullivan	205	1,390,500	10,891	9.2	1.4	15.8	379	0.052	0.04	0.21	0.21	0.56	0.68
Indiana	Vigo	184	3,552,700	10,345	10.5	1.1	17.3	451	0.076	0.06	0.25	0.27	0.61	0.73
Indiana	Warrick	157	3,360,169	11,126	10.1	3.4	12.7	255	0.099	0.03	0.14	0.13	0.47	0.58
Kansas	Crawford	86	0	11,815	13.1	3.3	7.6	1,813	0.066	0.24	0.40	0.49	0.74	0.98
Kansas	Linn	38	402,404	10,952	19.5	4.1	6.9	904	0.125	0.13	0.29	0.33	0.62	0.88
Kentucky	Bell	102	2,682,928	12,635	9.2	1.3	6.0	432	0.096	0.05	0.23	0.25	0.60	0.72
Kentucky	Boyd	16	434,400	12,306	10.8	0.9	7.4	748	0.081	0.14	0.32	0.38	0.73	0.84
Kentucky	Breathitt	200	998,449	11,965	10.2	1.1	8.9	829	0.103	0.14	0.32	0.38	0.72	0.86
Kentucky	Clay	22	538,378	12,399	9.8	1.4	7.6	2,800	0.219	0.39	0.50	0.62	0.84	0.98
Kentucky	Daviess	46	762,970	11,214	9.1	2.8	13.4	204	0.089	0.02	0.12	0.11	0.45	0.51
Kentucky	Estill	5	35,000	12,774	7.3	0.9	7.5	926	0.053	0.17	0.34	0.41	0.75	0.88
Kentucky	Floyd	233	4,572,011	12,194	10.9	1.0	6.9	1,291	0.093	0.23	0.39	0.48	0.79	0.94
Kentucky	Harlan	267	8,615,558	12,814	8.4	1.1	6.4	435	0.084	0.05	0.24	0.26	0.62	0.72
Kentucky	Henderson	108	1,740,717	10,601	13.0	3.4	12.6	231	0.143	0.03	0.13	0.13	0.46	0.56
Kentucky	Hopkins	230	4,878,580	11,466	12.0	2.8	9.5	531	0.087	0.07	0.23	0.23	0.57	0.77
Kentucky	Jackson	3	4,000	12,169	10.5	1.7	7.4	1,871	0.160	0.28	0.42	0.53	0.80	0.98
Kentucky	Johnson	76	1,692,200	12,107	10.5	1.3	6.9	1,049	0.155	0.17	0.35	0.42	0.74	0.91
Kentucky	Knott	412	6,317,410	12,685	8.7	1.1	6.6	1,264	0.093	0.22	0.37	0.46	0.78	0.94
Kentucky	Laurel	8	3,600	11,687	12.4	1.0	9.2	1,971	0.096	0.33	0.45	0.57	0.82	0.98
Kentucky	Lawrence	92	744,800	12,272	9.2	1.0	8.0	1,180	0.144	0.21	0.37	0.46	0.78	0.93
Kentucky	Leslie	206	3,268,782	12,640	8.8	1.1	6.8	1,229	0.074	0.21	0.37	0.46	0.77	0.94
Kentucky	Letcher	313	5,571,516	12,828	8.2	1.2	6.2	1,137	0.094	0.20	0.36	0.44	0.76	0.92
Kentucky	Magoffin	40	624,977	12,266	10.4	1.3	7.4	857	0.100	0.14	0.32	0.38	0.71	0.87
Kentucky	Martin	266	8,973,877	12,125	11.0	0.9	6.4	1,011	0.105	0.19	0.36	0.44	0.77	0.90

Kentucky	McLean	16	109,700	10,377	15.7	3.3	12.4	285	0.079	0.03	0.16	0.16	0.48	0.62
Kentucky	Muhlenberg	55	2,406,040	10,804	14.6	3.2	10.6	261	0.103	0.03	0.15	0.14	0.47	0.59
Kentucky	Ohio	3	114,910	11,045	12.0	3.5	11.6	343	0.110	0.04	0.17	0.17	0.50	0.66
Kentucky	Owsley	23	14,000	12,374	9.6	1.8	6.4	1,949	0.171	0.28	0.43	0.54	0.80	0.98
Kentucky	Perry	542	14,449,505	12,321	10.4	0.9	6.6	1,024	0.071	0.19	0.36	0.44	0.76	0.90
Kentucky	Pike	847	21,071,801	12,651	9.3	0.8	6.5	1,375	0.088	0.26	0.40	0.50	0.80	0.95
Kentucky	Pulaski	10	339,000	12,500	10.0	1.3	6.8	1,005	0.109	0.17	0.34	0.41	0.74	0.90
Kentucky	Union	225	8,861,664	12,059	9.5	2.5	8.9	1,786	0.093	0.25	0.40	0.50	0.77	0.98
Kentucky	Webster	153	6,295,809	12,236	10.3	2.7	6.8	1,821	0.099	0.25	0.40	0.50	0.76	0.98
Kentucky	Whitley	24	224,607	12,190	9.8	1.2	7.6	1,533	0.112	0.25	0.40	0.50	0.79	0.97
Louisiana	De Soto	59	2,105,000	6,936	12.0	0.9	33.5	155	0.093	0.02	0.14	0.10	0.46	0.46
Louisiana	Red River	38	705,000	7,117	12.3	0.7	32.5	161	0.059	0.02	0.15	0.10	0.48	0.47
Maryland	Allegany	29	85,414	11,608	18.5	1.7	4.9	162	0.200	0.02	0.12	0.09	0.44	0.45
Maryland	Garrett	116	3,053,274	12,442	14.3	1.7	5.6	943	0.202	0.14	0.32	0.38	0.70	0.89
Missouri	Bates	30	127,565	10,598	17.2	3.7	10.5	391	0.100	0.05	0.19	0.19	0.52	0.70
Montana	Big Horn	452	23,552,836	9,234	5.1	0.4	24.9	84	0.052	0.02	0.10	0.04	0.41	0.19
Montana	Richland	28	215,300	6,770	7.6	0.5	36.7	200	0.092	0.03	0.19	0.17	0.53	0.53
Montana	Rosebud	35	12,695,800	8,726	8.1	0.7	26.7	38	0.065	0.02	0.05	0.03	0.28	0.10
New Mexico	Colfax	7	472,300	11,962	14.9	0.6	4.7	134	0.055	0.02	0.14	0.09	0.48	0.38
New Mexico	McKinley	206	11,539,043	9,621	15.5	0.6	14.8	157	0.065	0.02	0.16	0.12	0.50	0.45
New Mexico	San Juan	101	15,133,000	9,090	23.8	0.8	10.5	80	0.087	0.02	0.09	0.04	0.39	0.23
North Dakota	McLean	45	7,150,000	6,181	11.4	0.7	37.6	114	0.098	0.02	0.12	0.07	0.43	0.37
North Dakota	Mercer	255	11,159,500	6,703	8.0	0.7	37.0	119	0.075	0.02	0.12	0.07	0.43	0.37
North Dakota	Oliver	68	5,989,200	6,789	9.0	1.0	36.5	188	0.121	0.02	0.16	0.12	0.48	0.51
Ohio	Belmont	422	5,459,600	12,269	10.3	3.8	6.3	486	0.126	0.06	0.21	0.21	0.54	0.75
Ohio	Carroll	3	29,200	12,190	11.8	2.6	6.0	669	0.300	0.10	0.26	0.29	0.61	0.82
Ohio	Columbiana	14	569,561	12,181	10.9	3.8	6.6	1,038	0.484	0.15	0.31	0.35	0.65	0.91
Ohio	Coshocton	49	2,156,500	11,987	7.4	2.7	10.2	825	0.243	0.12	0.28	0.32	0.64	0.86
Ohio	Guernsey	2	400	11,251	14.7	2.1	7.7	698	0.412	0.10	0.28	0.32	0.64	0.83
Ohio	Harrison	192	1,572,509	12,031	11.1	2.8	7.3	1,221	0.288	0.17	0.34	0.41	0.70	0.93
Ohio	Holmes	14	143,230	11,067	13.6	3.1	9.2	762	0.403	0.11	0.28	0.31	0.62	0.85
Ohio	Jackson	34	699,800	10,889	13.0	4.1	10.2	240	0.294	0.03	0.13	0.13	0.46	0.57
Ohio	Jefferson	36	246,800	11,894	11.6	2.3	7.6	741	0.163	0.11	0.28	0.32	0.64	0.84
Ohio	Mahoning	3	13,600	9,741	21.8	3.4	8.5	748	0.373	0.11	0.28	0.31	0.61	0.85

Ohio	Meigs	101	4,553,600	11,194	12.5	3.6	9.8	1,458	0.240	0.20	0.36	0.44	0.70	0.96
Ohio	Morgan	56	1,090,147	11,618	12.6	4.4	7.2	613	0.132	0.09	0.23	0.24	0.56	0.80
Ohio	Perry	91	290,600	11,247	11.6	2.8	9.9	267	0.297	0.03	0.16	0.14	0.48	0.60
Ohio	Tuscarawas	64	290,716	11,511	12.3	3.6	8.0	811	0.233	0.12	0.28	0.31	0.61	0.86
Ohio	Vinton	117	1,198,000	11,260	10.7	3.0	10.5	375	0.192	0.04	0.19	0.18	0.52	0.68
Oklahoma	Haskell	11	641,000	12,304	16.1	3.3	3.6	555	0.451	0.08	0.23	0.23	0.57	0.78
Oklahoma	Latimer	1	116,452	12,697	13.5	3.7	4.2	346	0.680	0.04	0.17	0.16	0.50	0.66
Oklahoma	Le Flore	28	510,000	12,220	16.2	3.4	3.8	498	0.459	0.07	0.22	0.21	0.55	0.75
Oklahoma	Rogers	36	111,704	12,764	10.7	4.0	4.2	2,034	0.075	0.25	0.40	0.50	0.75	0.98
Pennsylvania	Armstrong	20	4,405,083	12,174	13.9	2.7	5.5	1,735	0.388	0.24	0.40	0.49	0.76	0.98
Pennsylvania	Beaver	260	674,300	12,010	12.0	1.6	6.8	726	0.242	0.11	0.29	0.34	0.66	0.84
Pennsylvania	Bedford	8	371	11,633	14.8	1.5	6.9	887	0.418	0.14	0.32	0.39	0.71	0.88
Pennsylvania	Butler	6	135,730	11,029	16.2	2.9	7.4	858	0.298	0.13	0.30	0.34	0.64	0.87
Pennsylvania	Cambria	3	539,600	12,677	12.7	2.0	5.2	1,621	0.297	0.24	0.39	0.49	0.77	0.98
Pennsylvania	Clearfield	6	2,482,840	12,098	15.8	1.8	5.7	1,080	0.442	0.17	0.34	0.41	0.72	0.91
Pennsylvania	Elk	49	153,627	12,547	10.9	1.9	6.2	1,566	0.457	0.23	0.39	0.48	0.77	0.97
Pennsylvania	Fayette	62	516,829	12,639	8.4	1.6	7.8	882	0.162	0.13	0.31	0.37	0.69	0.88
Pennsylvania	Greene	908	23,468,283	13,091	7.7	2.0	6.0	976	0.113	0.14	0.32	0.38	0.70	0.89
Pennsylvania	Indiana	4	3,002,300	12,368	14.4	2.2	5.5	1,707	0.483	0.24	0.40	0.50	0.77	0.98
Pennsylvania	Luzerne	2	1,090,000	12,134	10.3	0.6	7.8	152	0.130	0.02	0.15	0.11	0.50	0.41
Pennsylvania	Lycoming	23	99,760	10,708	23.0	0.7	4.9	902	0.202	0.19	0.37	0.45	0.77	0.88
Pennsylvania	Northumberland	50	908,162	10,880	16.8	0.6	7.9	434	0.132	0.08	0.27	0.31	0.67	0.72
Pennsylvania	Schuylkill	7	123,000	8,913	28.5	0.5	10.2	377	0.180	0.07	0.27	0.31	0.67	0.70
Pennsylvania	Somerset	163	3,070,306	12,922	10.2	2.0	5.7	954	0.177	0.14	0.31	0.37	0.69	0.89
Pennsylvania	Washington	413	5,349,966	13,098	7.3	1.6	6.0	1,084	0.133	0.17	0.34	0.41	0.73	0.91
Pennsylvania	Westmoreland	27	677,091	13,007	8.3	1.6	6.3	1,375	0.216	0.21	0.37	0.46	0.76	0.95
Tennessee	Anderson	12	366,920	12,417	9.2	1.2	7.3	1,028	0.154	0.17	0.34	0.42	0.74	0.90
Tennessee	Campbell	1	878,000	12,277	9.3	1.1	7.8	342	0.126	0.04	0.21	0.21	0.57	0.66
Tennessee	Claiborne	24	473,746	12,890	7.4	1.3	6.6	383	0.105	0.04	0.22	0.22	0.58	0.68
Tennessee	Cumberland	15	258,260	12,508	11.8	0.7	6.7	812	0.049	0.16	0.33	0.40	0.75	0.86
Tennessee	Morgan	1	4,900	12,432	10.8	1.7	6.6	320	0.274	0.03	0.19	0.16	0.53	0.64
Tennessee	Scott	19	457,520	12,415	10.9	1.4	6.0	992	0.128	0.16	0.34	0.41	0.73	0.90
Tennessee	Sequatchie	34	429,140	12,039	13.2	0.8	6.7	1,106	0.069	0.22	0.38	0.47	0.78	0.92
*Texas	Atascosa	34	2,321,987	5,435	24.9	1.7	27.8	903	0.228	0.15	0.37	0.45	0.69	0.89

*Texas	Freestone	32	4,972,000	6,596	15.8	0.7	32.0	368	0.213	0.05	0.25	0.27	0.61	0.69
Texas	Harrison	48	3,627,000	6,511	15.2	1.2	33.5	132	0.299	0.02	0.12	0.09	0.43	0.42
Texas	Leon	12	9,216,000	7,020	18.2	1.1	26.8	222	0.141	0.03	0.18	0.15	0.50	0.57
*Texas	Milam	28	3,820,596	6,717	16.3	1.2	30.6	474	0.255	0.07	0.26	0.29	0.61	0.75
*Texas	Panola/Rusk	85	14,006,000	6,473	13.7	1.1	34.9	163	0.192	0.02	0.14	0.11	0.46	0.48
*Texas	Robertson	87	1,640,000	6,746	16.9	0.9	30.4	128	0.160	0.02	0.13	0.09	0.44	0.41
*Texas	Titus	88	13,773,236	5,994	17.8	0.5	33.8	175	0.399	0.03	0.19	0.17	0.53	0.51
Utah	Carbon	126	7,116,633	11,806	9.8	0.6	7.9	212	0.046	0.02	0.19	0.18	0.56	0.53
Utah	Emery	226	9,213,244	12,028	9.5	0.4	8.3	246	0.057	0.04	0.21	0.22	0.60	0.57
Utah	Sevier	91	2,137,309	11,347	8.3	0.4	10.3	107	0.058	0.02	0.13	0.08	0.47	0.29
Virginia	Buchanan	240	2,866,960	13,105	8.3	0.8	7.1	1,125	0.095	0.21	0.37	0.45	0.78	0.92
Virginia	Craig	18	0	13,969	5.9	0.7	5.5	1,132	0.083	0.23	0.37	0.45	0.78	0.92
Virginia	Dickenson	69	1,160,431	13,089	8.1	0.9	7.1	524	0.077	0.08	0.26	0.30	0.66	0.76
Virginia	Lee	56	3,018,031	12,911	8.1	1.1	6.1	110	0.060	0.02	0.09	0.04	0.41	0.28
Virginia	Russell	136	1,675,932	12,378	14.6	0.7	4.7	611	0.064	0.12	0.30	0.36	0.72	0.80
Virginia	Wise	846	10,775,002	12,852	9.7	1.0	6.3	300	0.086	0.03	0.20	0.19	0.56	0.62
Washington	Lewis	90	3,832,000	7,791	15.2	0.9	25.4	104	0.067	0.02	0.10	0.06	0.41	0.33
West Virginia	Barbour	38	853,922	13,084	9.5	1.4	5.9	1,672	0.157	0.26	0.41	0.51	0.80	0.98
West Virginia	Boone	1190	20,715,607	12,397	11.3	0.8	6.3	1,305	0.091	0.25	0.40	0.49	0.79	0.94
West Virginia	Braxton	8	22,187	12,636	10.3	0.8	6.6	1,338	0.136	0.25	0.39	0.49	0.79	0.95
West Virginia	Brooke	127	1,626,800	12,302	10.4	3.7	6.7	821	0.140	0.12	0.27	0.30	0.61	0.86
West Virginia	Calhoun	4	0	12,505	9.7	1.4	7.0	500	0.100	0.07	0.25	0.27	0.62	0.75
West Virginia	Clay	73	2,537,325	12,286	12.6	0.8	5.4	933	0.138	0.18	0.35	0.43	0.76	0.89
West Virginia	Fayette	166	1,780,810	12,076	13.0	0.9	6.6	1,036	0.098	0.19	0.36	0.45	0.77	0.91
West Virginia	Grant	113	1,146,830	12,403	13.5	1.7	6.1	1,147	0.231	0.18	0.35	0.43	0.73	0.92
West Virginia	Greenbrier	6	52,000	13,102	9.1	0.9	6.5	1,005	0.150	0.19	0.35	0.43	0.76	0.90
West Virginia	Harrison	19	6,038,722	13,244	6.9	2.9	5.7	743	0.090	0.10	0.26	0.29	0.62	0.84
West Virginia	Kanawha	671	11,638,342	12,053	13.5	0.8	6.0	970	0.095	0.19	0.36	0.44	0.77	0.90
West Virginia	Lincoln	24	226,700	11,420	14.4	0.8	7.1	798	0.091	0.15	0.33	0.40	0.74	0.86
West Virginia	Logan	369	4,276,078	12,168	12.4	0.7	6.0	1,051	0.088	0.21	0.37	0.46	0.78	0.91
West Virginia	Marion	13	903,123	13,339	7.1	2.1	5.4	1,294	0.063	0.19	0.35	0.43	0.73	0.94
West Virginia	Marshall	606	11,139,828	12,089	12.1	3.9	6.7	436	0.125	0.05	0.20	0.19	0.53	0.72
West Virginia	Mingo	452	15,413,902	12,123	12.4	0.9	6.5	1,074	0.082	0.20	0.37	0.45	0.77	0.91
West Virginia	Monongalia	516	7,848,526	12,705	10.3	2.1	5.6	858	0.114	0.12	0.30	0.35	0.67	0.87

West Virginia	Nicholas	141	3,237,943	12,286	12.3	0.9	6.1	1,036	0.143	0.19	0.36	0.44	0.76	0.91
West Virginia	Preston	18	1,237,017	13,126	8.8	1.4	6.4	1,768	0.157	0.28	0.42	0.52	0.80	0.98
West Virginia	Raleigh	7	297,700	11,339	17.7	0.9	7.2	797	0.110	0.15	0.33	0.40	0.74	0.86
West Virginia	Upshur	92	2,059,348	12,982	9.7	1.7	4.9	1,004	0.251	0.15	0.33	0.39	0.71	0.90
West Virginia	Wayne	417	5,279,621	11,935	11.5	0.8	7.5	1,027	0.118	0.20	0.36	0.45	0.77	0.91
West Virginia	Webster	268	4,494,014	12,529	12.0	0.9	5.0	1,381	0.121	0.25	0.40	0.50	0.80	0.95
West Virginia	Wyoming	17	622,069	13,471	7.3	0.8	5.2	1,189	0.059	0.23	0.38	0.47	0.79	0.93
Wyoming	Campbell	3819	288,722,919	8,616	5.1	0.3	28.5	129	0.069	0.02	0.16	0.12	0.51	0.38
Wyoming	Carbon	133	2,586,539	10,887	6.3	0.6	13.5	60	0.027	0.02	0.08	0.03	0.35	0.11
Wyoming	Converse	392	18,120,375	8,702	5.5	0.3	26.9	170	0.057	0.02	0.19	0.18	0.56	0.47
Wyoming	Lincoln	105	2,529,000	9,957	5.1	0.8	20.7	135	0.052	0.02	0.13	0.06	0.45	0.38
Wyoming	Sweetwater	116	9,168,000	9,402	9.5	0.5	20.1	102	0.051	0.02	0.12	0.04	0.44	0.29

Notes: Tons from FERC 423 (USEIA, 2003a) or Part 50 (USMSHA, 2004)
Btu, Ash, and Sulfur adjusted to a moist basis using Moisture estimated after Quick and others (2004a)
Fractional Mercury Capture calculated as the average result of equations listed in table 2 (this report); hESP is hot-side Electrostatic Precipitator; cESP is cold-side Electrostatic Precipitator; hESP/FGD is hot-side Electrostatic Precipitator with wet Flue Gas Desulphurization; cESP/FGD is cold-side Electrostatic Precipitator with wet Flue Gas Desulphurization; SDA/FF is Spray Dry Adsorption with wet Flue Gas Desulphurization.

* Mercury values revised to higher values after McCall (2004) and Eutizi (2005)

GLOSSARY

ASTM	American Society for Testing and Materials.
Btu	gross British thermal units per pound coal on a moist, whole-coal basis as reported from the laboratory(multiply by 0.002326 to convert to MJ/kg).
$Btu/lb_{m,mmf}$	British thermal units per pound coal, on a moist, mineral-matter-free basis calculated as, $Btu/lb_{m,mmf} = \frac{100\,(Btu/lb \;-50\,Sulfur\;)}{(100-[1.08\,Ash-0.55\,S])}$, where the sulfur, ash and Btu/lb values are on a moist, whole-coal basis.
Btu_{net}	Net British thermal units per pound coal, reported on a whole-coal, moist basis. Also called the lower heating value, this calculated value is less than the Btu value reported from the laboratory in proportion to the amount of water vapor in gaseous combustion products. It can be calculated as $= Btu \;-92.7(0.1119 Moisture + Hydrogen)$ where both Btu and hydrogen are reported on a moist basis, but hydrogen exlcudes hydrogen in coal moisture.
cESP	cold-side Electrostatic Precipitator. (see ESP)
ESP	Electrostatic Precipitator. Called a cold-side ESP (cESP) when installed downstream of the air pre-heater (where temperatures typically range from 140 to 160 ºC) and called a hot-side ESP (hESP) when installed before the air pre-heater (where temperatures typically range from 350 to 450 ºC).
FGD	wet Flue Gas Desulfurization. An emission control technology designed to remove SO2 from flue gas, usually installed after a particulate collection device; sulfur is removed as flue gas passes through an aqueous, alkaline solution (typically made with lime or limestone).
FF	Fabric Filter. An emission control device, also called a baghouse, that removes solid particles from combustion flue gas.
hESP	hot-side Electrostatic Precipitator. (see ESP)
lbs $Cl/10^9$ Btu	Pounds of chlorine per billion Btu $= \frac{10^9}{Btu} \times \frac{ppm Chlorine}{10^6}$, where Btu and chlorine values are on the same reporting basis (for example, both dry basis or both moist basis. Multiply by 0.430 to convert to kg Cl/TJ.
lbs $Hg/10^{12}$ Btu	Pounds of mercury per trillion Btu $= \frac{10^{12}}{Btu} \times \frac{ppm\,Mercury}{10^6}$, where Btu and mercury values are on the same reporting basis (for example, both dry basis or both moist basis). Multiply by 0.430 to convert to kg Hg/PJ.
lbs Hg/TW-h	Pounds mercury per terawatt hour, which is calculated in this report as: $= \frac{10^{12}}{Btu_{net}} \times \frac{ppm\,Mercury}{10^6} \times 10.26$ where both Btu_{net} and mercury are reported

	on a moist basis, and the coefficient, 10.26, corresponds to a nominal heat rate of 35% (exactly 9,750 gross Btu/kilowatt-hour, which is approximately 10,260 net Btu/kilowatt-hour).
lbs $S/10^6$ Btu	Pounds of sulfur per million Btu $= \frac{10^6}{Btu} \times \frac{\%Sulfur}{100}$, where Btu and sulfur values are on the same reporting basis (for example, both dry basis or both moist basis). Multiply by 0.430 to convert to kg S/GJ.
COALQUAL	Coal quality database from the U.S. Geological Survey.
CTRDB	Coal Transportation Rate Data Base from the U.S. Energy Information Administration.
daf	A dry, ash-free reporting basis, usually noted as a subscript associated with a coal assay value. Dry, ash-free basis values are obtained by multipling, moist, whole-coal assay values by the factor: $\frac{100}{(100 - Ash - Moisture)}$, where ash and moisture values are on a moist, whole-coal basis.
DOE	U.S. Department of Energy.
EIA	U.S. Energy Information Administration.
EPA	U.S. Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FERC 423	A monthly data set listing the cost and quality of coal delivered to U.S. power plants.
ICR	Information Collection Request. Data collected during 1999 by the EPA to assist the development of any rules to limit mercury emissions from coal-fired utilities. The part 2 data list coal assay data for coal shipments, the part 3 data list measurements of mercury in stack gas.
ppm	parts per million. Equals µg/g or mg/kg.
PRB	Powder River Basin. Refers to coal produced from Campbell, Converse, and Sheridan Counties, Wyoming as well as Big Horn and Rosebud Counties, Montana.
PSU	Pennsylvania State University.
SDA	Spray Dry Adsorption. An emission control technology designed to remove SO2 from flue gas, gaseous sulfur is converted to a solid sulfate when an alkaline mist is injected into the flue gas; the solids are then collected in a particulate filter. Usually used for low-sulfur western coal.
UGS	Utah Geological Survey
USGS	United States Geological Survey.